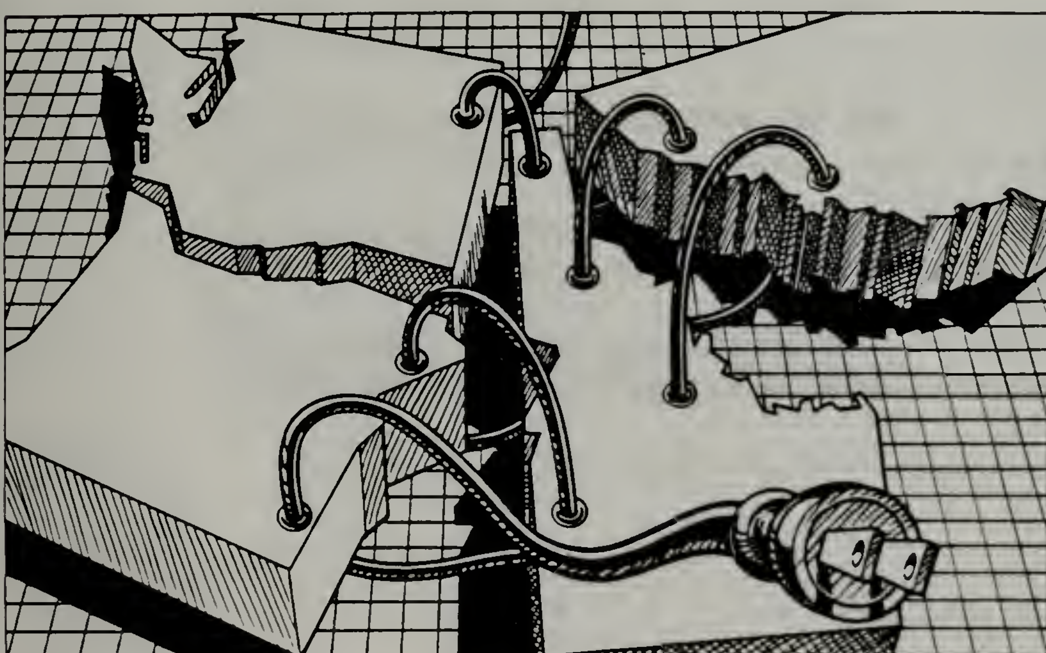
89-28

Pacific Northwest Coordination Agreement: Background and Issues

A Report Prepared for the Northwest Power Planning Council

by Lawrence A. Dean
and
Merrill S. Schultz



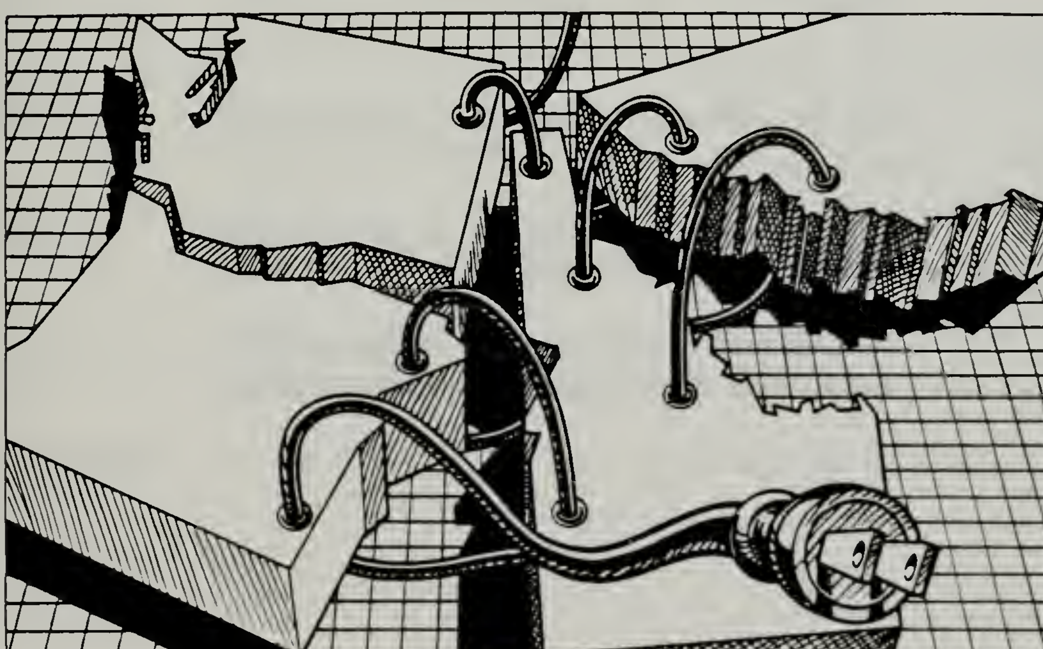
August 11, 1989

89-28

Pacific Northwest Coordination Agreement: Background and Issues

A Report Prepared for the Northwest Power Planning Council

by Lawrence A. Dean
and
Merrill S. Schultz



August 11, 1989

Table of Contents

NORTHWEST POWER PLANNING COUNCIL

851 S.W. SIXTH AVENUE • SUITE 1100
PORTLAND, OREGON 97204-1348 • (503) 222-5161

Toll free number for Idaho, Montana & Washington: 1-800-222-3355
Toll free number for Oregon: 1-800-452-2324

Introduction: The Pacific Northwest Coordination Agreement

The Coordination Agreement is a long, extremely complicated contract governing the rights and obligations of the Northwest generating utilities to receive and provide firm power (called Firm Load Carrying Capability or FLCC in the agreement) out of a total generating system operated to maximize the amount of firm power subject to non-power constraints. The signers include all the Northwest generating utilities except Idaho Power, and include as well the Corps of Engineers and the Bureau of Reclamation as reservoir owners.

The agreement was part of a package including the Canadian treaty and the sale of the Canadian entitlement to downstream power benefits to Northwest non-federal utilities via the Columbia Storage Power Exchange.[1] The agreement deals in most detail with coordination of the hydro system, since the package concerned the hydro system and there was very little significant thermal generation on the system at that time.

The basic problem addressed by coordination is twofold. First, an operating plan needs to be constructed that maximizes power production subject to non-power constraints from a system that has upstream storage projects and downstream run-of-river projects, different river basins with diverse weather patterns and history and finally, diverse ownership. This problem, while it existed prior to the treaty, was exacerbated by the addition of the large amount of Canadian storage, pursuant to the treaty. Second, there must be assurance that the operating plan so constructed will be carried out, and that diverse parties are assured of the power they had planned on receiving. The Coordination Agreement sets up the process for that planning among Northwest utilities (the treaty spells out the process for the Canadian projects vis-a-vis the United States) and binds the parties to carry it out.

The Council contracted with Mr. Dean and Mr. Schultz to write a report on the Coordination Agreement. Mr. Dean was director, prior to his retirement, of the Division of Power Supply at Bonneville and is now a private consultant. Mr. Schultz has been director of the Northwest Power Pool, director of the Intercompany Pool, and chairman of the Council's Reserves and Reliability Statistical and Scientific Advisory Committee and is now a private consultant. Both of them have been involved with the

---

1./ A staff briefing paper on the Columbia River Treaty and the Columbia Storage Power Exchange is available from the Council (request publication number 89-23).

agreement since its negotiation in 1964 and can provide an historical perspective that few others in the region could. The Council asked them to address four topics, asking each to write two original reports and two commentaries, so that each would be able to express his opinion on all four topics without excessive duplication. The four topics were the following:

1. The first topic is a description of what might be thought of as the boundary conditions of coordination. That is, how was the system operated before the signing of the agreement and what might the system look like without coordination? At the other extreme, if coordination were "ideal," how would it look and how would it be different from operation under the agreement?

2. The second general topic is the relationship of coordination to the Canadian treaty. What does the treaty actually require and to what extent does the treaty assume coordination in some form? For what treaty purposes is coordination assumed or required?

3. The third general topic is the historical evolution of the agreement. What specific historical circumstances led to the form of the agreement as it stands today? How has operation under the agreement changed between its signing and today and what problems led to those changes?

4. The fourth general topic is the relationship of operations planning under the agreement to long-term planning. What constraints does the former place on the latter? What implications does the latter have for the former?

chuck/kg/iadme

Topic 1

Boundary Conditions of Coordination

by Lawrence A. Dean
Commentary by Merrill S. Schultz

Topic 1(a)
Inter-Utility Coordination in the Pacific Northwest Prior to the Coordination Agreement

by Lawrence A. Dean

Two one-year and one ten-year coordination agreements preceded the long-term Pacific Northwest Coordination Agreement (PNCA) currently in effect. The first of the one-year agreements became effective on September 1, 1961. This section will describe the situation with regard to inter-utility coordination in the Pacific Northwest preceding that date.

Pacific Northwest utilities began to interconnect as early as 1923 when the municipal electric utility systems of Seattle and Tacoma were interconnected. Interconnections between regional utilities occurred periodically thereafter. The ability to interconnect the region's systems was greatly improved by the construction of federal transmission from Grand Coulee to load centers west of the Cascades in the early 1940s. In 1956 when the Bonneville Power Administration (BPA) interconnected with Idaho Power Company at La Grande, Oregon, exchange of significant amounts of power among all the generating utilities in the U.S. Pacific Northwest became possible.

One of the most important events in the coordinated operation of the Pacific Northwest occurred in the early 1940s when the federal government ordered electric utilities nationwide to interconnect and to pool their operations in order to more efficiently meet the nation's wartime power needs. In response, Pacific Northwest generating utilities established the Northwest Power Pool (NWPP). The region's investor-owned utilities provided the office space and staff for the original Coordinating Group office. Since that time, all of the region's utilities having major amounts of generation have become members of the NWPP, and staffing and offices are supported on a joint basis by all those utilities. At present all major generating utilities serving Washington, Oregon, Idaho, Montana, Utah and British Columbia are members of the NWPP.

The primary purposes of the NWPP are to provide a central clearing house for operational data and to provide guidelines to power system operations and operations planning. The NWPP has an Operating Committee composed of one representative from each member system. This committee provides a forum for discussing common operational problems and establishing guidelines. Most importantly in the context of this discussion, the NWPP operates entirely as a voluntary organization. No contracts bind the operations of its members. Guidelines agreed to by its Operating Committee are followed by its members on a voluntary basis.

Prior to 1961, the NWPP Coordinating Group prepared and published an Operating Program for each operating year. This Operating Program contained tabulations for the total NWPP and for each member system giving monthly firm and interruptible loads, energy and peak capabilities under both critical period and median streamflow conditions, and end-of-month elevations

for each major reservoir under both critical and median streamflow conditions. While the member utilities often compared their actual operations to these reservoir elevations and critical period capabilities during the operating year, they were under no obligation to follow these guides.

These NWPP Operating Programs assumed full coordination of the member systems' hydro and thermal resources. They determined the Pool's critical period in the same manner as later prescribed in the Pacific Northwest Coordination Agreement (PNCA) and drafted all Pool seasonal reservoirs from their nominal full to their nominal empty elevations during the Pool's critical period.

The single exception to the absence of required adherence to the NWPP Operating Program was the operation of the Idaho Power Company's Brownlee reservoir. After considerable contention, and after one revision, the license for Brownlee issued by the Federal Power Commission (now the Federal Energy Regulatory Commission) required the Idaho Power Company to coordinate the operation of the Brownlee reservoir with the Northwest Power Pool.

Another significant activity prior to the first coordination agreement in 1961 was the preparation of resource planning studies by the Pacific Northwest Utilities Conference Committee (PNUCC). This organization compiled a document annually which compared the sum of the regional utilities' forecasted firm loads to the sum of the their critical period capabilities over a 20-year planning horizon. This document was used to indicate the region's needs for new firm resources, and was submitted to Congress in support of requests for funding of new federal hydroelectric projects in the Pacific Northwest. While the reservoir operations and hydro capabilities of resources located west of the Cascades were prepared by the owners of these resources and submitted by them to the PNUCC for inclusion in this document, the regulation of all reservoirs and hydro projects on the Columbia River and its tributaries upstream of Bonneville Dam were prepared by BPA under the aegis of the PNUCC, and assumed full coordination and draft of all such reservoirs from full to empty during the region's critical period. As in the case of the NWPP Operating Program, the region's utilities were under no contractual obligation to actually operate their systems in this manner.

This is not to say that there were no contractual arrangements for coordinated operation prior to 1961. In 1958 The Washington Water Power Company, the Pacific Power and Light Company, and the Idaho Power Company completed a three-party contract covering some aspects of coordinated operation. In particular, this contract called for coordinated determination of the three parties' firm energy capabilities under critical streamflow conditions, and the establishment of a monthly "firm load carrying capability" for each system which the other two systems were obligated to support with "interchange energy." This concept found its way into the PNCA.

Coordinated operation of the reservoir at Flathead Lake was achieved in another way. A contract between the Montana Power Company and BPA called for the Montana Power Company to delay drafting water from Flathead

Lake at the beginning of each reservoir drawdown season (August and September) until the water could be used at downstream federal hydroelectric projects. To accomplish this operation, the contract obligated BPA to deliver to the Montana Power Company the energy which it would have generated at its projects from the water it otherwise would have drafted from Flathead Lake.

BPA power sales contracts also had an effect on the planned operation of those utilities which purchased power from BPA on the basis of their "computed demands." Under those contracts, a utility was obligated to buy from BPA the excess of its actual firm loads over its computed firm capability. The maximum amount of firm energy capability for which each utility customer could claim credit was determined by drafting all of its reservoirs from full to empty during that utility's critical period. For utilities having generation on the Columbia River, the regulations prepared for the PNUCC could be used. But for some smaller utilities the critical period was determined for them separately, and significantly limited the firm capability for which they could claim credit.

Another significant aspect of coordinated operation (or lack thereof) prior to the PNCA began when the federal Hungry Horse project began operating in 1952. This major reservoir is located at the headwaters of one of the main tributaries of the Columbia River, and numerous hydroelectric projects, both federal and non-federal, are located downstream from it. Because the reservoir capacity at Hungry Horse is much larger than the normal spring inflow to the reservoir, a large portion of the water in the reservoir is not drafted except during critically low streamflow conditions. The non-federal utilities owning hydro projects downstream from Hungry Horse, particularly The Montana Power Company with its Kerr and Thompson Falls projects and The Washington Water Power Company with its Cabinet Gorge and (later) Noxon Rapids projects, were quite unhappy with their inability to get water released from the Hungry Horse reservoir when they thought it should be released. BPA on the other hand was satisfied to release water from storage at Hungry Horse when, and only when, the federal Columbia River power system needed those releases. Because storage releases comprised such a large portion of the total flow at those four downstream projects during the critical period, they frequently were not able to generate as much during average or better streamflow conditions as they could during critically low streamflow conditions. The desires of management at these two companies to formalize the rules for releasing water from reservoirs like Hungry Horse and to make them into contractual obligations was one of the driving forces in the development of the PNCA. The PNCA negotiators developed the concepts of "Energy Content Curves" and "In-lieu Energy" to reconcile the diverse needs for storage releases between reservoir owners and downstream project owners.

Another factor giving impetus to long-term contractual coordination was the effort of the Federal Power Commission and Pacific Northwest utilities to determine the appropriate payments for benefits received by a hydroelectric project from regulation of storage at reservoirs upstream from that project. Section 10(f) of the Federal Power Act requires all hydroelectric project licensees which benefit from storage regulation at federal or non-federal reservoirs upstream from their project to share in the cost of those reservoirs. In 1952 the Federal Power Commission, at the request of the Bonneville

Power Administration, ordered a determination of headwater benefit charges for the Columbia River. Despite considerable effort, FERC and the region's utilities had been unable to reach agreement by 1961 on the appropriate level of these headwater benefit payments. During those negotiations it became apparent that storage benefits would be enhanced and storage payments increased if the storage were regulated pursuant to a firm, long-term coordination agreement.

The final and most important event giving impetus to the negotiation of the PNCA was the prospect that the Columbia River Treaty would become a reality. The changes in inter-utility coordination necessitated by the Treaty are discussed under Topic 2. With the exception of discussing that topic, the foregoing generally covers the situation with regard to inter-utility coordination in the Pacific Northwest prior to 1961 when negotiation of the first one-year Pacific Northwest Coordination Agreement was begun in earnest.

Topic 1(b)
Inter-Utility Coordination in the Pacific Northwest in the Absence of a Broadly-Based Coordination Agreement

by Lawrence A. Dean

It is hard to imagine a future in which the utilities of the Pacific Northwest would operate without some form of broadly-based coordination agreement, such as the Pacific Northwest Coordination Agreement (PNCA). Given that by the year 2003 the region's utilities will have operated under the PNCA for 39 years, it seems unthinkable that there would not be contractual coordination dealing with at least the water and energy aspects of operating those hydraulically interconnected reservoirs and generating plants located in the Columbia River basin. This is particularly true because the Columbia River Treaty, and its obligations to deliver half of the Treaty benefits to Canada, will continue in effect beyond 2003.

The material following in this section obviously is speculation, and should be treated as such.

To even make the assumption that there would not be some sort of long-term, broadly-based regional coordination agreement, one would have to speculate that the spirit of cooperation among the region's utilities had sunk to an all-time low, or, more likely, that legal or environmental entanglements had precluded or delayed the execution of such an agreement.

If one had to speculate, one might assume that inter-utility coordination would return to the conditions existing prior to 1961. That is, that resource planning and operations planning would assume coordinated release of storage from the region's reservoirs, but that no broad agreement would be in place to implement that assumption. Also that there would be some contractual agreements in place between smaller groups of utilities providing for certain more limited aspects of coordination. These agreements probably would be for a relatively short number of years. One key to agreements between a relatively small number of utilities is that in such agreements each party would be confident that it will receive a fair share of the benefits from the agreement, or it would not become a party to the agreement.

The absence of a broadly-based coordination agreement might mean that the headwater benefit payments assessed by the Federal Energy Regulatory Commission (FERC) would not be based on coordinated water releases from upstream reservoirs. One might expect this would result in lower headwater payments. However, based on the formulas the FERC has recently applied to headwater benefit payments in other parts of the United States, such payments might be even higher than they are under the existing PNCA.

Topic 1(c)
"Ideal" Coordination in the Pacific Northwest

by Lawrence A. Dean

The following material approaches the question "What would 'ideal' coordination look like in the Pacific Northwest" in two ways. The first approach is to answer the question "what deficiencies does the existing agreement have?," and the second approach is to step back and take a general view of inter-utility coordination.

I. Deficiencies in the Existing PNCA

Aside from the problems which have arisen in administering the existing Pacific Northwest Coordination Agreement (PNCA) (which are discussed under Topic 3), the existing PNCA has a number of important aspects of inter-utility coordination which it simply does not cover.

It was intentionally designed not to apply to the planning and construction of new resources by the parties to the agreement.

It was intentionally designed not to apply to the sale of firm power among the parties to the agreement. The agreement recognizes that a party might have a surplus or deficiency of firm resources (firm load carrying capability or FLCC) relative to the firm load it reasonably expect to be obligated to serve. The agreement limits the support a party has a right to receive from the other parties to the amount necessary to support its FLCC. The party's additional needs, if any, to enable it to meet its firm obligations are outside the agreement. This was significant in 1977 when certain utilities within the region had insufficient firm resources to meet their firm loads. Clearly, the PNCA was not the vehicle to address that problem. The governors of the States convened a task force for the purpose of developing a "regional curtailment program" to be implemented by the region's utilities. Eventually, the crisis went away before the task force did anything about it. This subject arose again when the BPA regional act power sales contracts were negotiated. In section 11(a) of its utility power sales contracts BPA makes a commitment to enter into negotiations as soon as practicable between it and the region's utilities to develop an agreement which will deal with inter-utility deliveries of energy made available by a regional load curtailment program ordered by the appropriate governmental bodies. But in eight years those negotiations have not commenced, and they probably will not until the next regional energy crisis occurs.

The PNCA was intentionally designed not to apply to short-term operations. All rights and obligations under the agreement are to monthly energy or daily capacity, and all deliveries of power among parties are prescheduled daily for the hours of the following day (or days, in the case of weekends). Moment-to-moment operations are outside the agreement. After the PNCA was in place, the owners and purchasers of power from the five non-federal hydroelectric projects downstream from the federal Chief Joseph project found this to be a very significant deficiency. As a result, BPA, the

Corps of Engineers, the Bureau of Reclamation, and those owners and purchasers developed the "Mid-Columbia Hourly Coordination Agreement." This agreement covers the moment-to-moment aspects of coordinating the electrical and hydraulic operations among the two federal and five non-federal hydroelectric projects at and immediately downstream from Grand Coulee. This agreement was originally executed in 1972 for a term of ten years. It has been extended from time to time, and has recently been renewed for a term of ten years.

The Idaho Power Company (IPC) was not a signatory of the PNCA. Despite the fact that the IPC owns and operates the Brownlee reservoir, a major reservoir upstream from eight major federal hydroelectric projects, BPA and the IPC could not reach agreement on Brownlee headwater benefit payments and other issues which existed at the time. The IPC is not now a party to the PNCA, nor do they or the parties to the agreement seem to have a current interest in the IPC becoming a party to the agreement.

The PNCA was developed at a time when the Pacific Northwest did not depend of large thermal generating plants to supply any significant amount of firm power. The agreement permits the parties to include their thermal resources in the annual planning process, and thereby to use the region's hydro system to shape the energy capabilities of these resources to loads. It also uses all the submitted thermal resources to compute the required amounts of forced outage reserves, and provides for deliveries of capacity to back up both hydro and thermal unit forced outages. However, the agreement provides almost no ability of thermal plant owners to reshape thermal plant energy capabilities once the annual planning process is completed, nor to get any energy backup to thermal plant outages.

II. General View of Inter-utility Coordination

There are a number of approaches two or more utility systems may take to coordinated operation. As discussed in the following paragraphs, they range widely, and the benefits they provide, such as maximizing ability to serve firm loads or preserving each utility's operating autonomy, vary widely.

In the most general terms, electric power system coordination usually means the generation planning and/or operation of two or more separately owned electric power systems without some of the barriers to efficient planning/operation normally present because of the separate ownership. Obviously, the simplest and most effective way to accomplish such "coordination" is to merge the ownership of the systems. Equally obviously, this often is not feasible. When coordination is desirable but merged ownership is not, a coordination contract between two or more systems can be used to <u>approach</u> the ideal of a single ownership system.

Sufficient interconnection capacity must exist or be added to permit the exchanges needed to accomplish the desired coordination, or interconnection capacity must be recognized as a limiting factor. When new interconnection capacity must be added, its cost must be taken into account in evaluating the economic benefits which may be realized by the coordination.

Again in general terms, the objective of coordination is usually to serve a given amount of load at the least long-run cost for the combined systems, or to serve the greatest amount of load for a given combined long-run cost. This general objective is often defined in terms of delaying the need to add the next firm resource, or to enable the combined systems to sell an additional increment of power. Sometimes, given a fixed set of resources, minimizing the operating costs of the combined systems is taken as the objective.

Diversity among systems usually is the thing that makes coordination profitable: diversities among the time of day that peak loads occur; diversities among the seasons that peak or heavier energy loads occur; diversities among the planned and forced outages of thermal units; diversities among the costs of operating thermal generation; diversities between predominantly thermal and predominantly hydro systems; diversities among the streamflow regimes of hydro systems; diversities among the times that hydro system reservoirs empty or fill; etc. Bigger systems are not necessarily better systems if diversities do not exist among the systems to be coordinated.

In order to contractually enable two or more systems to take advantage of the diversities between them, the coordination contract must establish a procedure for determining when power will be transferred from the system of one of the coordinated utilities to the system of another. What that procedure will be, and how it will work best will depend on what diversity is being coordinated. Generally, the procedure will recognize the existence of some condition within the system and give a right to receive power to one system and an obligation to deliver that quantity of power to another system. The system having a right to receive the transfer may be obligated to take the power, or it may have the right to refuse the transfer. Priorities of such coordination obligations relative to each system's other firm obligations depend, of course, on the wording of the coordination contract. Obligations under the coordination contract need to have a fairly high priority to assure that the benefits of coordination will be realized.

Among the predominantly thermal systems of the eastern U.S., the advantages of coordination come mainly from diversities in thermal plant efficiencies and fuel costs. The ability to receive help during thermal unit maintenance and forced outages also provides significant advantages from coordination. Coordination contracts among such systems would therefore be quite different from contracts among Pacific Northwest systems which are predominantly hydro systems.

Most of the diversities in the Pacific Northwest come from differences in streamflow regimes and the refill characteristics of reservoirs. Therefore, the Pacific Northwest Coordination Agreement (PNCA) sets up an annual process for determining end-of-month rule curves at each reservoir and a process for determining monthly amounts of firm energy to which each system is entitled. Rights and obligations to transfer energy between systems are based on these quantities. Another type of diversity which the PNCA addresses is the diversity in ownership of generating plants in series on a river. This is particularly a problem in the Columbia River basin where more than a dozen utilities own reservoirs and generating plants where the operation of one can affect the water flow at another.

Since diversity is the source of most coordination benefits, the diversity (or lack thereof) between an individual system and the total coordinated system is a very important factor in determining whether that individual system will automatically receive a fair share of the benefits of coordination. If such is not the case, that system may want to have the benefits of coordination explicitly determined by the contract and divided among the parties. It is interesting to note that, because the federal system comprises about half of the total system coordinated under the Pacific Northwest Coordination Agreement, there is little diversity between the federal system and the coordinated system. Further, despite some attempts by BPA during the negotiations of the PNCA and its predecessor agreements, the PNCA does not evaluate benefits and divide them among the parties to that agreement.

The following briefly discusses five different types of inter-utility coordination, and their advantages and disadvantages relative to each other.

Merged ownerships. The ultimate in coordination between two or more utility systems would be to merge the ownership of the utilities, to merge the management of the utilities, to merge their operating staffs into a single operating staff, and to replace their multiple automatic generation control (AGC) systems with a single AGC system. The merged management can define the objectives for the combined system. Merged ownership definitely can maximize operating efficiencies and firm load carrying capabilities compared to the alternative forms of coordination discussed below. Transfers of power between the merged systems no longer even have to be accounted for. The need for duplicate management, operating staffs and control equipment is eliminated. There are also disadvantages. Obviously, this method is not feasible in many cases. When feasible, existing utilities lose their identity. The elimination of duplicate management and staffing may not be considered to be an advantage, especially by those to be eliminated.

True pooling. Under this alternative, a contract would provide for replacing multiple operating staffs and AGC systems with a single staff and AGC system. That staff has the responsibility for operating the combined systems in the manner prescribed by the contract. Generating resources are dispatched without regard to ownership in the most efficient manner for the pooled system, and the costs of operating those resources are borne by the parties to the contract in accordance with the terms of the contract. The obvious advantages of this type of coordination are that a single staff is able to operate the system very efficiently, assuming that is the objective of the pooling contract. This type of pooling operates in real time, and thus avoids the problems and inefficiencies of scheduling interchanges between separate AGC areas in advance. This method is likely to be less efficient than the merged ownership alternative. It requires extensive after-the-fact accounting of power uses and costs. Individual utilities lose some autonomy and control over the use of their resources. As in the first alternative. the elimination of duplicate operating staffs may be regarded as an advantage or disadvantage, depending on whether or not you are among the staff to be eliminated.

The reader should note that the Northwest Power Pool, despite its name, is not a power pool in the sense that term is used in the discussion above.

Coordination contracts. Under this alternative, each utility retains its own operating staff and continues to operate its own AGC equipment. Transfers of power between systems are determined and priced in advance of the fact, and are scheduled between the AGC systems of pairs of utilities. Such transfers are usually firm obligations to deliver on the delivering system and, in some cases, firm obligations to receive on the receiving system. These obligations are determined in accordance with the coordination contract, and may depend on a number of factors such as loads, streamflow and reservoir conditions, unit outages, fuel prices, etc. Although this method is theoretically able to achieve the operational efficiency of single ownership, it usually falls short of that objective. It has the advantage that each utility retains its own identity and, subject to its obligations under the coordination contract, control of its own generating resources, loads and sales. Needs for duplicate management and operating staffs are not eliminated. Computation of rights and obligations under the contract are complex and difficult. Before-the-fact determination of rights and obligations leads to some improper transfers.

The Pacific Northwest Coordination Contract is an example of this type of coordination.

Firm transfers. Under this alternative, some degree of coordination is achieved by having two or more utilities contractually agree to transfer power under certain conditions, such as during certain months of the year to account for seasonal diversity between systems, or when certain streamflow, reservoir, unit outage or other conditions occur. The determination of contractual obligations is usually not as complex as under a "full coordination contract." This alternative retains autonomy of each utility's management and operating staff. The biggest disadvantage is, of course, that the benefits able to be achieved usually fall far short of the benefits possible with other arrangements discussed above.

Seasonal energy and/or capacity exchanges between Pacific Northwest and California utilities are an example of this type of coordination. In a sense, even seasonal firm power sales would be an example. The Flathead Lake agreement which existed between the Montana Power Company and BPA prior to 1961, and the 1984 Non-Treaty Storage Agreement between BPA and the British Columbia Hydro and Power Authority also would be an examples of this type of coordination.

Opportunity transfers. Under this alternative a measure of coordination is achieved simply by having enabling contracts under which one utility "may offer" to deliver some power and the other "may accept" the offer. Terms governing the eventual sale or return of the power are set forth in the contract. It achieves the least benefits of the alternatives listed, but it is better than nothing. Under this alternative each utility retains full autonomy and control over system operation.

Agreements providing that one utility may store energy in the reservoirs of another, such as those between BPA and the British Columbia Hydro and Power Authority are examples of this type of coordination. The economy interchange arrangement used by the Western Systems Coordinating Council (WSCC) a few years ago would also be an example of this type of

coordination. Under that arrangement, dispatch offices of all the WSCC members were connected by computer terminals. Dispatchers could offer to sell power prior to each hour, and the dispatchers of other companies could opt to buy some or all of that power for the coming hour.

III. Summary-"Ideal" Pacific Northwest Coordination

Now, given all of that background on advantages and disadvantages of various types of coordination, the question is: "What would 'ideal' coordination look like in the Pacific Northwest?"

At one extreme, merged ownership offers the maximum efficiency with the greatest loss of autonomy. Opportunity transfers guarantee total autonomy and can achieve benefits worth literally millions of dollars, but do not even come close to the benefits of other types of coordination.

What is best for the Pacific Northwest? What does the Pacific Northwest want? The merger of Pacific Power and Light Company with the Utah Power and Light Company is probably an isolated case of merged ownership in this region. Over the years the region's utilities, including BPA, have repeatedly shunned merged dispatch and AGC facilities. True pooling seems to be out of the question in the Pacific Northwest.

At present 13 utilities serving the states of Washington, Oregon, Idaho and western Montana operate separate control centers and automatic generation control (AGC) equipment. Even the region's investor-owned utilities, who have an organization known as the Inter-Company Pool, do not operate as a pool or combine the operation of any of their control centers.

There is a disturbing trend in the règion toward more, not fewer, separate generation control centers. Douglas County PUD began operating an independent generation control center thirteen years ago. Cowlitz County PUD began independently scheduling power with other utilities about 15 years ago, but the Cowlitz loads and resources operate within the BPA automatic generation control area. When Snohomish County PUD's Sultan project began operating about five years ago, Snohomish began scheduling power in a fashion similar to that used by Cowlitz. It now appears that Pend Oreille County PUD may begin scheduling power independently.

The Bonneville Power Administration has in some cases helped facilitate these independent control centers and in other cases has offered contracts which avoid the need for such centers. For example, BPA has enabled the scheduling activities of Cowlitz, Snohomish and the Eugene Water and Electric Board by permitting them to schedule across the BPA AGC boundaries, and thereby avoid the cost and other problems associated with the operation of separate AGC equipment. It probably would not be feasible for these utilities to schedule independently if BPA did not allow them to operate within its AGC area. It might also be more difficult for these utilities to schedule independently if they were not parties to the Pacific Northwest Coordination Agreement.

On the other side, BPA has offered and continues to offer what it calls "Service and Exchange" contracts to each of its public agency customers who

have small amounts of generation and do not choose to operate that generation independently. Under these contracts, the utility assigns its rights to the output of the resource to BPA in exchange for billing credits and cash payments which are calculated based on the capability of the generation. The resource is operated within the BPA AGC area at the direction of the BPA schedulers. At present, such contracts are in effect for the mid-Columbia project purchases of the Okanogan County PUD, the Kittitas County PUD, the City of Milton-Freewater, the City of Forest Grove, and the McMinnville Water and Light Department. The operation of Snohomish's Sultan project under such a contract was favored by BPA, but rejected by Snohomish. The BPA Service and Exchange contracts are an example of a high degree of coordination.

In the final analysis, the coordination presently being achieved by the Northwest Power Pool and the the Pacific Northwest Coordination Agreement is probably the most desirable type of coordination for the Pacific Northwest. To the extent practicable, the deficiencies in the PNCA noted above should be remedied in any successor agreement. The formation of new control centers should be discouraged.

Topic 1(a)
Inter-Utility Coordination in the Pacific Northwest Prior to the Coordination Agreement

Commentary by Merrill S. Schultz

In comments to the NWPPC Staff, we have both noted the overlap between this part of Mr. Dean's assigned subjects and the first issue of my assignment. To a large extent, the characteristics of operations prior to the Agreement, as described by Mr. Dean, were the circumstances leading to the form of the current Agreement, which I was requested to address. Although we have identified many of the same issues, I believe, or at least hope, that our different perspectives on those issues keep the reports from being repetitious. However, providing yet additional remarks on the background of the Agreement probably would be regarded as redundant, and I have no further commentary to add to the subject.

Topic 1(b)
Inter-Utility Coordination in the Pacific Northwest in the Absence of a Broadly-Based Coordination Agreement

Commentary by Merrill S. Schultz

I agree emphatically with Mr. Dean's statement that it seems unthinkable there would not be contractual coordination at least among the operators of the hydraulically linked facilities in the Columbia River Basin. Coordinated operation of those projects is not only of immense benefit to the people of the region overall, but it is beneficial to each individual interest in the River system--power, fish and wildlife, irrigation, flood control, navigation and recreation. One may responsibly argue that the current coordinated operation has the wrong priorities, but, whatever priorities and purposes might be established to direct the operation, the operation will far better serve those purposes if it is coordinated.

The Council asked, "What might the system look like without coordination?" For the power system, my answer is that it would look chaotic and stupidly inefficient. The system was built around the idea of coordinated operation. Not to have a coordination contract now would be as if a group of people had joined together to build a condominium and then failed to provide a mechanism for the joint management of the facility.

Yet, I perceive the possibility that there might not be a long-term successor to the current Agreement in place when it expires. As in the days before the PNCA, everyone will agree that coordination is beneficial, but they will disagree about structure. Unlike those days, however, the system which depends on coordination has already been constructed; a party whose current situation was secured only by committing to coordination many years ago might not view the trade-offs now as having the same weights as they did then. In addition, there are many new actors on the scene who will demand satisfaction of their narrow, disparate and perhaps mutually contradictory interests. A litigious and absolutist atmosphere seems to pervade interactions in an industry which had never experienced a major lawsuit until coordination was fifteen years old. The specter of people, even non-parties, saying, "You coordinate my way, or you will not coordinate at all," is very real to me.

Topic 1(c)
"Ideal" Coordination in the Pacific Northwest

Commentary by Merrill S. Schultz

In describing the Coordination Agreement which they sought, and created, the parties were careful to avoid using the word "maximum" (or even "ideal") and carefully chose instead the word "optimum." By this exquisitely subtle choice, they intended to mean that the Agreement embodies a finely wrought balance between the potential efficiencies of a centrally managed monolith and the more subjective advantages, safeguards and sensitivities of local autonomy. It is perhaps presumptuous to compare this balance to that incorporated in the U.S. Constitution, but some of the same competing philosophies were expressed in the negotiations of both.

As Mr. Dean points out, the Agreement lacks a number of features that would have brought the Region "True Pooling," and he also notes that those features were excluded quite deliberately. They were not simply overlooked. Mr. Dean describes the absences of some of these features as "deficiencies;" I am sure that he does not use the term as a value judgment, but rather as a way of identifying the ingredients missing from the Agreement, if the Agreement had been intended to be a recipe for a True Pool. It was not so intended and, although the principle of autonomy has been increasingly diluted in the years since 1964, it is still strong enough (e.g., Sections 2(5) and 4(g)(2) of the Regional Power Act) to render the achievement of True Pooling highly improbable.

Surely, there are some gains of efficiency which could be made, theoretically, by moving from the coordination of the existing PNCA to a True Pool. Small steps toward that end can probably be accomplished within the Region's current institutional structure. Some of those kinds of steps have been taken, by the way, both within and outside the Agreement. In my Sections of this report, I described some of the improvements that have been made in the functioning of the Agreement itself. Mr. Dean mentioned the separate Mid-Columbia Hourly Coordination Agreement--by any standard, I believe, one of the best power pooling contracts ever written. The Northwest Power Planning Council was established by the Regional Power Act to provide coordinated Regional power resource planning.

From its own experience in Regional planning, the Council should be keenly aware of the limitations which the underlying political and institutional structure imposes upon achievement of True Pooling. For the Regional cluster of pooling arrangements to have come as close as possible to True Pooling within those limitations cannot be regarded as a deficiency of the arrangements.

Excepting his use of the word "deficiencies," I agree with Mr. Dean's conclusions. The kind of coordination in existence now is probably the most desirable type of coordination for the Region as it exists institutionally. Incremental steps in the direction of True Pooling should be attempted continuously and adopted as conditions permit. And the proliferation of small

generation control areas should be halted, and rolled back if possible, through creative contracts.

Topic 2

Relationship of Coordination to the Columbia River Treaty

by Lawrence A. Dean
Commentary by Merrill S. Schultz

Topic 2
Relationship of Coordination to the Columbia River Treaty

by Lawrence A. Dean

The level of coordination existing in the Pacific Northwest prior to 1961 and the effect it had on the negotiation of the Pacific Northwest Coordination Agreement (PNCA) are described in Topics 1 and 3 of this report. The most important event giving impetus to the negotiation of the PNCA was the prospect that the Columbia River Treaty with Canada would become a reality.

As noted in Topic 1, prior to 1961 the region's utilities, acting through both the Northwest Power Pool and the Pacific Northwest Utilities Conference Committee, were making resource planning and operations planning studies which assumed the region's hydro and thermal resources would be operated as if they were a single system.

The hydroelectric regulation studies prepared by the Bonneville Power Administration (BPA) and the Corps of Engineers for the purpose of determining the benefits which could be obtained from various proposals for development of storage upstream in Canada were made in the same way. Later when the Columbia River Treaty protocol and the Columbia Storage Power Exchange (CSPE) sale were being negotiated in 1963-64, these BPA and Corps of Engineers studies were used to develop a document which set forth the estimated Treaty benefits at selected years in the future (the so-called White Book).

As noted in Topic 1, although the utilities made resource planning and operations planning studies assuming single system operations, there were no contracts which guaranteed the utility systems would actually be operated in that way. Since BPA controlled most of the reservoir storage and more than half of the generating capacity included in those studies, BPA might have been willing to undertake the commitment to Canada without an agreement which assured an operation consistent with the single system assumption. However, the owners and purchasers of the non-federal plants which were to benefit from the regulation of water under the Treaty could not afford to make a commitment to deliver the Canadian benefits to Canada without some contractual assurance that the assumed operation would actually occur.

The prospect of having to make that commitment led those utilities to demand from BPA that a coordination agreement containing certain provisions would be forthcoming before they could support ratification of the Treaty by the U.S. Congress. A set of principles which were to be the basis for the negotiation of the Pacific Northwest Coordination Agreement were agreed to by then Administrator Charles Luce and approved by then Secretary of Interior Stewart Udall on March 3, 1961.

In a March 15, 1961 letter to all BPA customers, Administrator Luce says that BPA, the Corps of Engineers, and the Bureau of Reclamation met

with the region's generating utilities on March 3 and March 6, 1961. He states: "At this meeting the Government presented general Principles of Coordination to form the basis to start negotiations of coordination agreements. To assure maximum use of our water resources, coordination is very desirable. With the Canadian Treaty, coordination becomes imperative."

The last sentence of this quote precisely states the relationship between the Columbia River Treaty and the Pacific Northwest Coordination Agreement.

Topic 2
Relationship of Coordination to the Columbia River Treaty

Commentary by Merrill S. Schultz

Mr. Dean concludes, in his quotation of Administrator Luce, "With the Canadian Treaty, coordination becomes imperative." I suggested in my part of this Report that the primary causal linkage between the PNCA and the Treaty was that the Treaty, in one stroke, assured the construction of about 20.5 MAF of new storage upstream from the mainstem Columbia River projects. Mr. Dean notes that the obligation of the United States under the Treaty to make headwater benefit payments (in the form of the Entitlement) to Canada depends on the assumption of coordinated operation of the U.S. Base System.

Neither of us, I think, made the point adequately that the Treaty does not simply assume coordination in the Northwest, but it appears to require coordination (Article III(1)):

> "The United States of America shall maintain and operate the hydroelectric facilities included in the base system and any additional hydroelectric facilities constructed on the main stem of the Columbia River in the United States of America in a manner that makes the most effective use of the improvement in stream flow resulting from operation of the Canadian storage for hydroelectric power generation in the United States of America power system."

Article III(2) goes on to say that the U.S. may discharge that obligation by assuming that such operation exists in any determination of downstream benefits. Granted, the Treaty is a covenant between the U.S. and Canada, and the second clause of the Article says that Canada is indifferent to the U.S.'s carrying out of the first clause so long as the Entitlement is determined as if it were carried out--but the intent of the U.S. to foster coordination is still clearly expressed.

That it was the intention of the two countries to achieve coordination through the Treaty--not just between them, but also among the systems within each country--is stated strongly in the IJC Principles, December 30. 1959, which were the basis for the Treaty:

> "Power Principle No. 7
>
> In addition to benefits from cooperative use of stored water, interconnection and coordination of the electric power systems to the extent that they are practicable and desirable, would also provide many mutual benefits which should be shared. Coordination being a continuing function would require specific arrangements

on the part of the operating agencies as the need arises.

"Discussion of Power Principle No. 7

The first six power principles recommended in this report are directed to determination and apportionment of benefits which would result from international cooperation in the use of stored waters. These are basically hydraulic benefits which can be realized by storing flood flows during the spring and summer months and releasing the stored waters during the fall and winter months when they can be put to use for the production of firm power at the storage site and downstream. Electrical interconnection between the power systems of the two countries would be required to make possible delivery of the upstream country's share of the power produced in the downstream country from the use of stored waters, but the interconnection capacity provided for this purpose would be only that needed to accomplish such delivery. This limited degree of interconnection would not, however, make possible the greater benefits that would accrue to the two countries from a comprehensive plan of inter-connection and coordination.

"Such coordination should be recognized in the development of the agreed upon plan of upstream storage operation and in the computation of system power benefits. Separate arrangements may be required for sharing coordination benefits because the electrical coordination envisaged could extend geographically beyond the service areas of the generating plants or power systems directly benefitted by the release of stored waters from storage projects constructed by the upstream country. It is recognized that the power systems in British Columbia are not now developed to the same extent as in the United States portion of the Columbia River basin, but it is the intention of this principle to provide for long-range international cooperation between the systems of the two countries as they continue to develop in the future.

"Under arrangements for coordination, it would be expected that all participating power systems would retain their local autonomy but would necessarily operate their generation and transmission facilities under the terms of appropriate agreements with a view to maximizing mutual benefits. The arrangements should set forth the broad operating principles to be observed and should be written in

sufficient detail to describe the specific purposes and objectives."

Furthermore, the linkage between the Treaty and the Coordination Agreement is manifested in both directions. As I mentioned in my part of the Report, the Operating Plans for Treaty Storage are constructed on the basis of a set of Principles and Procedures (POP) which have been worked out between the Entities. The US Entity was successful, to a great extent, at the outset in achieving its goal of incorporating in the POP the operating rules of the Coordination Agreement. Despite several modifications of the POP since Treaty Storage became operational, it still incorporates that set of rules. For example, the Assured Refill Curves for Treaty reservoirs are constructed in the same fashion as are Energy Content Curves under the PNCA; Treaty Storage participates in proportional draft--to meet U.S. FELCC--just as do the US reservoirs. One should not assume, however, that the Canadian Entity will automatically accept any change of the PNCA as a matching modification of the POP.

Topic 3

Historical Evolution of the Pacific Northwest Coordination Agreement

by Merrill S. Schultz
Commentary by Lawrence A. Dean

Topic 3
Historical Evolution of the Pacific Northwest Coordination Agreement

by Merrill S. Schultz

I. To Get an Agreement

Introduction

It is widely known that the single event which triggered the achievement of the Pacific Northwest Coordination Agreement (PNCA) was the Columbia River Treaty, signed by the governments of the United States and Canada in January 1961. The forces that led to the PNCA had been building up, however, for many years before that event, and the issues addressed by the PNCA have a wide array of sources in addition to the Treaty. Although the signing of the Treaty ensured that there would be a PNCA, the clamor for such an agreement had reached a high pitch even before the International Joint Commission's Principles for the Treaty were published in December 1959, and the provisions of the PNCA go far beyond what would be required only to deal with the operation of Canadian storage.

The benefits of a formal arrangement for coordinating the electric power supply operation of the region had been appreciated by all parties for a long time and, of course, no one was opposed to coordination. But there were strong differences of opinion about the acceptable structure of enhanced coordination and the resulting distribution of benefits. In general, the dispute pitted the non-Federal generating utilities against the Bonneville Power Administration; efforts toward coordination had come to an impasse, which was finally broken in favor of the non-Federal position. The non-Federal generators were prepared to oppose ratification of the Treaty unless the Government committed to BPA's participation in a coordination contract based on the principles advanced by the non-Federal utilities. The Government relented and, in March 1961, proposed a set of principles which promised the non-Federal parties the coordination agreement structure they demanded and, in return, secured non-Federal participation in the delivery of the Canadian Entitlement, as well as non-Federal support for the Treaty. Those principles, commonly called the Secretary's Principles, were the foundation for the current PNCA and for each of its three predecessors.

The form of the PNCA had an importance reaching far beyond the complex framework of that contract. It established a regional institutional relationship and an accepted means of approaching any problem of a recognized regional nature which prevailed at least until the Northwest Power Act became law at the end of 1980.

It is illuminating to recount the circumstances, interests and problems which came together to make the structure of the PNCA.

Power Pooling

Power pooling is a common practice among groups of neighboring electric utilities and is generally established in order to enhance mutual reliabilities and economies. The term is applied to a wide range of arrangements--from informal to formal, from single-purpose to fully integrated and from covering only operations to including resource planning, construction and ownership. The benefits of power pooling arise primarily from diversities of many kinds among the member utilities and from economies of scale available to larger entities. Historically the degree of integration achievable in a power pool has been a function of the similarity among member utilities in size, institutional species and prior independence.

The Northwest Power Pool, formed in 1942, is an informal, voluntary pool whose purview is restricted to electric system operations and performance. Although it performs many valuable services for its members, the NWPP has no mechanisms for assuring the individual member the transfers of power needed to take advantage of diversities. The PNCA provides a number of such mechanisms; examples include the use of the composite Critical Period as a basis for all parties' individual Firm Load Carrying Capabilities (FLCCs), the right of each party to obtain transfers of Interchange Energy and Capacity to support those FLCCs and the right of each party to store currently excess energy in any other party's reservoir which has space available. In most cases, the structure of the PNCA awards the largest gains achieved by blending diversities to the parties which individually would be the most diverse with respect to the composite system. For example, the FLCC gains realized through use of a combined system Critical Period are not allocated, but rather accrue to those parties whose own critical periods would be different from the Coordinated System's.

Assured Storage Operation

A major aspect of the PNCA, and one which makes it unique among power pooling agreements, is the provision of assured storage operation. This is the element which ties the PNCA to the Treaty, although it was an important issue in the Northwest before the international developments were proposed. Every party in the PNCA has generation downstream from storage owned and operated by others; thus, each party is dependent to some extent for its FLCC and for its operating economics upon the storage operation of one or more other parties.

The PNUCC West Group Forecasts, the NWPP Operating Programs, individual utilities' capability determinations and the Treaty benefit analyses were always based on the assumption of coordinated storage operation. Yet there was no firm commitment by any party, prior to the first PNCA, to operate its storage in conformance with that assumption. Increasingly during the 1950s, first with the completion of Hungry Horse Reservoir and then with the licensing, construction and operation of a large number of non-Federal projects downstream from Federal reservoirs, which provided the preponderance of storage in the Columbia River Basin, the weakness of the coordination assumption was revealed.

The non-Federal generators became determined to achieve an arrangement which would assure them of receiving releases of annually refillable upstream storage under all conditions and, in adverse water conditions, the storage they needed to produce FLCC. The imminent construction of Treaty Storage. which (including Libby) would add almost 21 MAF of Federally controlled upstream storage. brought this issue to the boiling point. Another important factor linked to the issue of assured storage operation was:

Headwater Benefit Payments

Section 10(f) of the Federal Power Act, which became law around 1920, provides, in pertinent part:

> Whenever any licensee hereunder is directly benefited by the construction work of another licensee, a permittee, or of the United States of a storage reservoir or other headwater improvement, the [Federal Power] Commission shall require as a condition of the license that the licensee so benefited shall reimburse the owner of such reservoir other improvements for such part of the annual charges for interest, maintenance, and depreciation thereon as the Commission may deem equitable. The proportion of such charges to be paid by any licensee shall be determined by the Commission.

The FPC had never made such a determination for the projects of the Columbia River Basin, but there was an FPC Docket established in 1952 for doing so--staff assigned to the project were having a difficult time of it. Should the benefits of Federal storage be treated as "incidental," even though the non-Federal project owners were claiming FLCCs based on full release of such storage under critical water conditions? Or should the benefits be treated as "assured," despite the fact that non-Federal project owners had no firm rights to get the claimed releases?

In addition, as can be seen from the above quotation, Section 10(f) does not require the United States to pay for benefits conferred on a Federal project by an upstream non-Federal reservoir. This lack of symmetry was a source of great unhappiness among the non-Federal reservoir owners. During 1960, in fact, there was legislation introduced in Congress to amend the Federal Power Act to require:

- that the Government would have to pay upstream providers of benefits at Federal projects; and

- that the Government would have to coordinate the operation of its projects with others.

The Bill did not succeed on the initial attempt, and further legislative effort was soon terminated when the parties agreed to include a settlement of the issue in a coordination agreement providing assured storage operation.

Computed Demand

From its earliest days, BPA had sold firm power to partial-requirement (i.e., generating) public agencies on the basis of Computed Demand. This was a billing scheme invented to maintain an equitable balance, in BPA's view, between (1) a supplier which had to dedicate resources at all times to meeting a customer's requirements under infrequent conditions of adverse streamflows; and (2) a customer whose actual requirements, in most years, would be significantly smaller, because flows are usually better than critical. The guiding principle of Computed Demand was that the customer would buy from BPA the amount of power which it would otherwise have installed to meet its load, rather than the increment of power which it actually needed at any time.

In keeping with that principle, Peak and Energy Computed Demands were determined for each period as the respective differences between actual peak and energy loads and Peak and Energy Assured Capabilities; the Assured Capabilities were specified and approved in advance of each year. Those Capabilities were based on the customer system's own critical period and included adjustments for reserves. If a customer was deemed to possess "seasonal storage," the billing periods were months; otherwise, ten-day periods were used. A system of billing ratchets completed the implementation of the "otherwise-installed" principle.

The twenty-year power sales contracts which BPA negotiated with the companies of the Intercompany Pool in 1953 provided that, if BPA determined it could meet those companies' requirements, they too would be served on the basis of Computed Demand. When the contracts were signed, this was thought to be a very unlikely eventuality, but, in fact, only a few years later it came about--and those companies remained on Computed Demand until the contracts expired in 1973. Thus, virtually all the non-Federal parties with which BPA was negotiating coordination were BPA's requirements customers; their gains of capability would be directly translated into reductions of purchases from BPA.

It is impossible to determine how much of the non-Federal pressure for coordination arose from long-range goals of maximizing regional efficiency and how much came from immediate incentives to reduce their BPA billings under the instant rate structure--but the latter imperative was surely a real factor.

Proposals

As noted earlier, all parties in the Region favored the concept of coordination; all supported the goal of achieving the efficiencies that would accrue to the Region if the entire system were operated by a single owner. The differences between the non-Federal generators and BPA regarding an acceptable structure were, however, profound.

The non-Federal utilities advocated an agreement among the parties which would provide each autonomous operation within a framework of defined rules, rights and obligations. The principles proposed by the non-Federal systems are described comprehensively in the Blue & Gold Book and are distilled succinctly in the Secretary's Principles.

Responding to the other parties in 1959, BPA put forward a suggested coordination scheme by which, at BPA's discretion, the owner of non-Federal hydroelectric project might assign the variable output of the plant to BPA in return for a firm delivery of power, shaped to load and fully backed up. The amount of firm delivery would be adjusted for the value of services determined to be provided in this conversion process by BPA, the value of the project's secondary energy to BPA and the headwater benefits provided the project by Federal reservoirs. This proposition was vigorously rejected by most of the non-Federal utilities--although by no means all of them. The structure of a short-lived BPA/Seattle agreement for the coordination of Boundary Project was similar to the BPA proposal; the existing contract for the handling of Okanogan PUD's share of Wells Project has some of the same features and, in fact, the New Resources Pool of the Northwest Power Act has at least a vestigial resemblance to the concept.

The non-Federal parties were successful in using their leverage in the Treaty ratification process to persuade the Government to accept principles for a coordination agreement based on the structure proposed by the non-Federal utilities, and in return the non-Federal utilities agreed to contribute a proportionate share of the Canadian Entitlement determined under the Treaty. The Secretary's Principles of March 1961 set forth the elements of the agreed structure; note that the document includes a Principle covering Headwater Benefit Payments which not only requires the non-Federal beneficiaries of Federal reservoirs to make such payments, but also commits the Government to pay for headwater benefits provided by non-Federal improvements, "consistent with applicable laws."

The parties set to work quickly, and the first Pacific Northwest Coordination Agreement was executed as of September 1, 1961.

II. From Agreement to Agreement

The First Agreement

The first PNCA had a term of only one year. The Recitals pointed out that all parties intended to accomplish a long-term agreement and that they wrote a short-term PNCA in order to secure the advantages of coordination for 1961-62, as well as to obtain experience in coordinated operation to assist in the negotiation of the long-term agreement. Seattle City Light, Tacoma City Light and Idaho Power Company were not signatories, despite their having participated in the negotiations.

The agreement dealt only with energy; its Firm Load Carrying Capabilities are equivalent to Firm Energy Load Carrying Capabilities in the current PNCA. Its procedural language was limited to the area of actual operation. All the quantities resulting from the operations planning process were stipulated in a set of exhibits--these include the Critical Period, Critical Period Energy Capabilities, Firm Load Carrying Capabilities. Critical Rule Curves, Energy Content Curves and Plant Data. There were no procedures included for computing Headwater Benefit Payments, either; the "bottom-line" net payments were simply specified in the body of the contract.

The agreement incorporated one very important departure from the Secretary's Principles. Principle (c) called for release of storage upon demand of a downstream party, or energy to be supplied in lieu thereof, if such water is in excess of the reservoir owner's "needs to carry firm loads and its anticipated secondary loads." Arguing that the mechanism for In Lieu Energy which they proposed would not alter a reservoir owner's ability to meet firm or secondary loads, the non-Federal parties succeeded in negotiating provisions which gave the downstream party the right to water above the Energy Content Curve, irrespective of any consideration of load.

Energy Content Curves (ECCs) were fixed for the entire year; neither the reservoir owner nor the downstream parties had rights to use water below those ECCs, except as such water might be needed to meet the total system's FLCC or as required to be evacuated for non-power purposes, such as flood control.

<u>The Second Agreement</u>

The second PNCA was also a one-year contract, covering 1962-63. It incorporated few changes from the first agreement, probably because the negotiators had obtained only limited experience under the 1961-62 PNCA by the time when they had to assemble the 1962-63 Agreement.

In Lieu Energy was the operational aspect of the PNCA which was almost the sole focus of the parties' attention from the beginning. There had been no transactions of Interchange Energy during the term of the first PNCA (indeed, there would be none of any significance until 1973 and none made clearly pursuant to the Agreement until 1979), and transfers of Storage Energy had not created much controversy. Frequent meetings of the Contract Representatives, starting almost immediately upon the execution of the first Agreement, were held to resolve disputes over the treatment of In Lieu Energy. Because the downstream party was to receive In Lieu Energy on a schedule neither more nor less favorable than such party's ability to generate with the water that was demanded, strict adherence to the principle injected tremendous complexity into the scheduling process. Could the requested water be released from the reservoir project within its turbine capacity or its naturally restricted discharge capability? Would the water be entrapped in an intervening reservoir against the same constraints? What is the combined lag-time of the various river reaches between the reservoir and the downstream project (lag-times could be several days)? How could a downstream project operator be prevented from making the sum of its In Lieu Energy schedule and its actual generation in any hour greater than its installed capacity, thereby getting a capacity benefit from In Lieu Energy? Were the parties using consistent answers to these questions both for deliveries and for returns of In Lieu Energy?

Either in the first year or at the start of the second year, the Contract Representatives attempted to bring some order to the situation by publishing a set of Methods and Procedures for In Lieu Energy, which memorialized agreed resolutions of past significant disputes. Some of these Procedures were incorporated in later versions of the PNCA, but many were left outside the body of Agreement, to be reaffirmed or changed annually, because they were considered either too detailed or too changeable. In this way began the

practice of implementing coordination through two companion documents, (1) a formal, fairly generally articulated contract; and (2) a short-term set of detailed operating interpretations, having a less formal appearance but no less binding. Later this second document was expanded and renamed Methods and Procedures for In Lieu Energy and Provisional Energy; the current outgrowth of this essential adjunct of the PNCA is simply called the 1988-89 Operating Procedures.

One significant new provision of this PNCA, no doubt based on experience with In Lieu Energy in the first Agreement, was that all generating units at each project would be deemed to be in service for all determinations regarding In Lieu Energy.

The Third Agreement

In 1963, the first multi-year PNCA was executed; it had a nominal term of ten years, but the parties intended that it would be superseded by a longer-term Agreement when (and if) the Treaty was ratified or when other developments caused the Critical Period to exceed one year. This Agreement contained several major changes from its predecessors:

1. Because of its multi-year term, it included extensive procedures for annual operations planning and for determining headwater benefit payments.

2. It dealt with peak loads and resources.

3. A new category of diversity exchange, Holding Interchange Energy, was added.

4. It permitted adjustment of Energy Content Curves based on runoff forecasts.

Obviously, stipulation of annual operating parameters was not feasible in a PNCA with a term of ten years. The set of procedures which was provided is similar to that of the current PNCA:

1. In advance of each year, the parties would exchange basic load/resource data.

2. A Preliminary Regulation would be run, so that each party would know its Critical Period Energy Capability.

3. Each party would then make certain permitted adjustments, including shaping of Firm Surplus Energy, and submit revised data.

4. A Modified Regulation, run to produce maximum Coordinated System FELCC, would be produced.

5. The parties would then meet, make desired and limited adjustments in the operation of their reservoirs and schedule Holding Interchange Energy (see below).

6. The Final Regulation would be run, from which Critical Rule Curves and official FLCCs would be derived.

7. Energy Content Curves for "cyclical" reservoirs would be determined.

Surprisingly, it appears that there was no procedure provided for determining the Critical Period itself and, although it is clear that the Agreement was intended to deal only with Critical Periods shorter than one year (there were no mechanisms provided for handling multiple-year Critical Periods), there was no mention of that limitation in the text.

Also because of the multi-year term, a general procedure for computing Headwater Benefit Payments had to be specified. The steps and formulas articulated in this Agreement were essentially the same as those which had been used to derive the stipulated quantities in the one-year PNCAs:

1. For each reservoir, the annual costs borne by power were to be submitted by the owner.

2. The annual cost would then be allocated between the power function and the storage function, based on Critical Period energy quantities--with the tacit understanding that only positive releases of storage would be considered.

3. The annual storage cost would then be allocated to all affected projects, at-site and downstream, on the basis of Critical Period energy generation from storage, but with a value-based limit of 0.55 mills/kWh.

It should be noted that the procedure considered only Critical Period storage benefits. Soon after this PNCA was executed, the Federal Power Commission adopted the procedure almost verbatim in its Regulations for Section 10(f) determinations nationwide, for all cases of assured storage operation. And that adoption included the fixed limit of 0.55 mills/kWh. The parties also provided a long, elaborate Refusal Option, by which a downstream party might escape payment in return for delivering the reservoir owner the energy generated from storage releases. That Option and the similar Option included in the long-term PNCA have never been invoked.

One of the common features of pooling agreements in the industry is provision for sharing reserve requirements; it had been assumed from the outset that the long-term PNCA would contain such provisions, even though the Secretary's Principles do not reference the subject. Also from the outset, discussions of it had strong Computed-Demand overtones, and negotiation of the part of the Agreement dealing with peak loads and resources was, as a result, contentious. In the ten-year PNCA the Coordinated System Forced Outage Reserve was to be computed by more-or-less standard Loss-of-Load-Probability (LOLP) techniques. This mathematically sophisticated phase of the process was understood by few of the negotiators but was accepted quickly. What occupied most of the three years of negotiation on the subject was the allocation method. The reserve requirement computed by use of LOLP is generally most sensitive to two factors, individual generating unit forced outage probability and individual generating unit size, and the latter is usually the single most important factor. System size is relatively

unimportant. At the time of the negotiation, the Federal system was by far the largest party, but its biggest units were the 125-MW Grand Coulee generators. Several of the non-Federal systems had units almost as large and were planning thermal units even larger. They supported the "equal-percentage" allocation; in this method the Coordinated System's Forced Outage Reserve is expressed as a percentage of the Coordinated System's peaking capability, and each party's Reserve is defined as the same percentage of its peaking capability. Others, chiefly BPA, advocated a method in which the Coordinated System's Forced Outage Reserve would be allocated to the parties based on their individual reserve requirements determined as if they were independent, isolated systems. In the end, the "isoprobability" method was adopted; the concept of isoprobability is that all parties carry amounts of reserve which sum to the total Coordinated System requirement, and each party has the same probability of requiring forced-outage backup from others. Provisions for forced-outage backup were included, but no other interactions to take advantage of peak load/resource diversities were provided.

Holding Interchange Energy was invented primarily to make the PNCA attractive to Seattle City Light and Tacoma City Light, although the device was beneficial, as well, to other parties whose own storage complexes were situated on Columbia River tributaries or coastal streams. These streams experience their freshets earlier than the mainstem Columbia, and their flows recede much earlier, too. As a result, the off-mainstem parties had always begun to draft their reservoirs as early as July or August, prior to coordination, while the drawdown season on the mainstem did not start until around the first of October or even later. Coordinated, all reservoirs would stay full until perhaps September 1, and little draft could be made in September and October. The off-mainstem parties perceived a pattern being imposed in which they would "hold" their reservoirs almost full in September and October of each year. They would serve their loads in those months with Interchange Energy delivered by the mainstem parties, but they would not be able later to return the Interchange Energy in most years. Then they would have to pay for the Interchange Energy imbalances, perhaps at thermal energy prices. Under this PNCA, a reservoir party with indicated imports of Interchange Energy in the periods from the start of the Drawdown Period through October could, if that party wished to draft its own storage but was constrained from doing so, take Holding Interchange Energy (HIE) instead. HIE was special in that its delivery and return were scheduled prior to the year, and in no event would the original receiving party be forced to purchase the energy. Incidentally, Seattle and Tacoma did not sign the Agreement, anyway.

BPA had devised a runoff forecasting technique for Hungry Horse Reservoir prior to coordination and had used it advantageously to produce energy from good snowpacks in advance of the freshet. The fixed Energy Content Curves of the one-year Agreements did not permit such beneficial use of forecasts. The new Agreement contained a clause allowing a reservoir owner to draft below ECC, so long as the forecast indicated high confidence of refill. Such additional releases were to be made at the sole discretion of the reservoir owner; downstream parties were not given the rights to demand the release or to receive In Lieu Energy from the extra water.

The Long-Term Agreement

The ten-year PNCA had been in effect only for a few months before successful international negotiations near the end of 1963 made it clear that Canada would ratify the Treaty and a U.S. entity would purchase the Entitlement for a term of 30 years starting with the operation of each Canadian reservoir. The negotiators set a deadline of September 30, 1964, for the completion of the entire complex package required to consummate the deal. Feverish work began early in 1964 on all elements of the package, including the long-term Coordination Agreement. It is difficult to describe the transformation of the ten-year PNCA into the current Agreement as a smooth, logical process because of the interplay of functions, people and proposals which took place among the groups that were working in parallel on the host of projects.

At some point early in the process, the parties agreed to split the Treaty-related issues between two contracts. The PNCA would include those provisions required for operation of the Canadian Storage, and a set of bilateral Allocation Agreements would deal with matters connected with the Entitlement. Thus, two of the Secretary's Principles for Coordination were not included in the PNCA; these were the intra-U.S. allocation of the Entitlement obligation and the sale of capacity by BPA to utilities contributing shares of the Entitlement. Furthermore, despite the intent of the Secretary's Principles to apply to the life of the Treaty, both the Allocation Agreements and the PNCA terminate along with the CSPE purchase of the Entitlement, in 2003.

The major tasks facing the PNCA negotiators were to add provisions for Restoration, as called for in the Secretary's Principles, and to expand the provisions of the ten-year Agreement so as to accommodate multiple-year Critical Periods, together with the system changes and additions which were expected to occur in its 39-year term.

Projects not downstream from Treaty Storage, but downstream from relatively substantial existing storage in the U.S., suffered reductions of Firm Energy Load Carrying Capability from lengthening of the Critical Period. The primary cause of the longer Critical Period was, of course, Treaty Storage. Secretary's Principle (d) promised the owner of such a "losing" project the right to purchase energy from the owners of "gaining" projects. The debate over implementation of this Principle was long and hard, and a method was finally adopted whereby Restoration was accomplished by a zero-sum set of FELCC adjustments among the parties--rather than by purchases. Determination of Restoration was inserted into the operations planning process as part of, and based on the results of, the Preliminary Regulation.

Until this negotiation few of the negotiators had expended much thought on the operating aspects of multiple-year Critical Periods. Such Critical Periods had always been distant, somewhat abstract, planning matters. And in the planning arena, they were universally handled on a "no-load-growth" basis. In that method, the load/resource balance for a future operating year is determined by matching a sequence of water years against a repetition of the loads and resources of the single operating year in question. The effect of this structure is to assign each operating year a hydroelectric resource roughly

equal to the Critical Period average hydroelectric energy capability; that is, it assumes inherently that there is no year-to-year shifting of hydroelectric energy within the Critical Period. If the planner's intention was to add new resources to match load growth closely, this method of determining need suited such an intention well.

However, the method contained quirks which ill suited it for use in operation. With a two-year or four-year Critical Period, load growth could be met adequately by installing every second year a new resource whose energy capability is twice the annual load growth; however, in such a case the "no-load-growth" concept would indicate a pattern of alternating annual surpluses and deficits. Monthly shaping was also a problem. For example, a new thermal plant scheduled to be in service halfway through the operating year would be shown as appearing each January 1 and disappearing each June 30 during the Critical Period, thus affecting the shaping of hydroelectric energy production, and reservoir operation, in each year. Finally, the method was incapable of realistic treatment, even for planning purposes, of new storage facilities, which must be filled before their operation is in steady-state. For example, Mica Project was scheduled to be in operation April 1, 1973. In the PNUCC West Group Forecasts of that time, all the data shown for 1972-73 reflected non-existence of Mica; however, the data for 1973-74 was based on the assumption that Mica began that year not only in existence, but also completely full, at least to the extent of Treaty Storage.

To overcome these shortfalls, the parties devised the "load-growth" method of dealing with multiple-year Critical Periods. Here, each sequential water-year is matched against a sequential contract year's loads and resources; that is, the continuum of water-years is assumed to occur within a continuum of contract years. This allows the system to accommodate non-uniform patterns of new resource installation and new reservoirs, and to concentrate Critical Period energy surpluses into the initial months of the Critical Period. It should be kept in mind that there were no analytical tools available to the authors of these procedures which were able to simulate their creation--the first hydro regulation computer program which could directly represent the "load-growth" approach was not written until 1967. Although problems with the procedures have turned up from time to time in the years since the PNCA was executed, the concepts have been demonstrated to be well founded.

Other notable changes include:

- A more comprehensive treatment of Firm Peak Load Carrying Capability was provided, creating a new type of transaction, Interchange Capacity, to take advantage of capacity diversities other than forced outages among the parties. Forced Outage Reserve and its allocation were left unchanged, in general, from the ten-year PNCA--albeit not without a great deal of dispute.

- The adjustment of Energy Content Curves on the basis of runoff forecasts was made mandatory, through procedures for determining Variable Energy Content Curves. The ability to use good runoff before its actual appearance as inflow would now be available to downstream parties, as well as the reservoir owner.

- The Headwater Benefit Payment procedures were altered significantly in an attempt to reflect the changing benefits of storage in the system as amounts of thermal capability and other secondary energy markets increased. The weighted average of Critical Period energy and average annual usable energy was substituted for Critical Period energy in the apportioning formulas. The weighting constant, called the "j-factor," was the subject of intense debate (and quite a lot of low humor) during the negotiation. The value-based limit on the annual payment to any reservoir was also modified, perhaps mistakenly; it was defined as $4.38 times the weighted sum of Critical Period average storage energy and average annual storage energy, rather than the weighted average of the two quantities. As a result, when the "j-factor" increases, the payment limit increases.

- Provision was included for renegotiating the charges other than Headwater Benefit Payments. The most significant of these Other Charges are the prices for Interchange Energy Imbalances. Before July 1 of every fifth year, any party is at liberty to give notice of desired changes and, if the parties cannot reach agreement on a new set of charges before the next January 1, the issue is to be submitted to FPC (now FERC).

- A special Section was added relating to Canadian Storage. Through these provisions the Government committed to act as the Reservoir Party for such Storage, as if it were a part of the Federal Columbia River Power System, except to the extent that the effective Treaty Operating Plan does not permit such treatment. The Government also committed to use its best efforts, as the U.S. Entity under the Treaty, to secure Operating Plans which would achieve optimum operation of the Treaty Storage for the Coordinated System.

- Holding Interchange Energy was redefined to apply to the first two Periods of the Critical Period.

III. Since the Agreement

Introduction

Looking at the volume and complexity of the Coordination Agreement, which contains more than fifty pages of closely spaced text, as well as a number of exhibits, one might have the impressions that all possible questions have been answered and that all possible situations have been addressed. Such impressions would be wrong. Starting on virtually the first day of operation under the first PNCA, there have been disputes over interpretation of the Agreement, and problems have arisen with great frequency which either were not covered by any provision of the Agreement or were not treated reasonably by relevant provisions. The parties have found in each case, however, means to avert the fatal stalemate and to go forward on the basis of mutual understanding. Sometimes they have reached permanent resolution, but in many instances they have temporized, "just for this year," only to have the same dispute arise year after year.

Operations Planning

Problems of many kinds have surfaced in the annual operations planning, but few have caused substantial, long-term changes of the process. Some of the more important issues were, or still are:

- Inability to shape Critical Period energy due to physical constraints. As noted earlier the parties provided treatment of multiple-year Critical Periods on a "load-growth" basis, despite having no analytical capability to test the product. It was generally assumed that hydroelectric energy generation could be moved about within the Critical Period as needed to match FELCC to the load shape, regardless of the unevenness of the residual load to be met by hydro. No one noticed, apparently, that the four-year "no-load-growth" Critical Period, which has a uniform use of hydroelectric energy, indicated storage content going very close to full at the end of the first year and very nearly empty at the end of the third Drawdown Period. If less than the uniform amount of hydro energy is used in the first year, therefore, the system might go out the top, and if more than the uniform amount is used in the first three years, the system might go out the bottom. These problems occurred several times in the first years of experience with the multiple-year Critical Period, and they were exacerbated in some instances by having a Critical Period for the Coordinated System different from the one on which the Canadian Storage Operating Plan was based. In all cases, however, the parties worked their way around the difficulties, and no permanent changes of procedure were made.

- Inability to shape Critical Period energy due to artificial reservoir constraints. Before generation was installed in Mica Project, the Canadian Entity permitted the Coordination Agreement parties to modify the Assured Operating Plan for Treaty Storage (the Plan produced six years in advance) almost at will during the PNCA operations planning process and accepted the results as the basis for the year's Detailed Operating Plan. However, beginning in 1978, the Canadian Entity no longer allowed any deviation from the Assured Operating Plan (AOP). The Principles and Procedures governing the production of the AOP, as agreed by the Entities, have always directed the AOP Critical Rule Curves to be developed on the basis of a "no-load-growth," or uniform-hydro, regulation. The action of the Canadian Entity meant that, at once, all the nonuniformities of the hydro residual load, whether for achieving load/resource balance or for shifting Critical Period firm surplus energy, had to be reflected in the operation of U.S. reservoirs. In the early 1980s, these nonuniformities grew quite large, as several of the PNCA parties attempted to shape their growing firm surpluses of energy into the early part of the Critical Period. The resulting impacts on annual refill probabilities of U.S. reservoirs were beyond the Corps' and the Bureau's thresholds of pain and, in the mid-1980s, the Corps imposed limits on first-year FELCC by means of declaring minimum permissible first-year-end elevations for Federal reservoirs. The parties have accommodated these constraints by concocting a series of allocation schemes to parcel out the now very limited system ability to shift FELCC into the first year of the Critical Period. No permanent method has been adopted, and each year brings new disputes and new schemes.

- Inability to shape Critical Period energy due to Water Budget. The studies performed in the 1950s in connection with the IJC and Treaty evaluations showed that at some point in its evolution, the region's power system would have so much thermal capability that the four-year Critical Period would begin to contain periods of unshapable energy capability. Starting perhaps with each July in the Critical Period, the combination of thermal energy and minimum hydro generation would exceed load. As still more thermal would be added, these periods of unshapable energy would expand until the Critical Period would disappear entirely. With 1963's High Load Forecast, this whole process would have run its course during the term of the PNCA. The negotiators believed this eventuality had to be covered in the PNCA, and it was--in Section 6(c)(3). Although the negotiators had no inkling of Water Budget, they had quite fortuitously provided the means to deal with it; the event which might have been expected to have a terrific impact on PNCA procedures actually was handled very smoothly.

  It is perhaps unfortunate that the PNCA deals with embedded periods of unshapable energy by leaving them in the Critical Period and forcing the FELCC for such a period to equal the period's energy generation, rather than by simply deleting those periods from the Critical Period. The negotiators probably selected their alternative so that individual parties which can reduce their generation to or below their loads during such periods would still have the benefits of their shaping capability. However, because in the PNCA neither the Critical Period Energy Capability nor the Critical Period average FELCC is affected when such periods occur, it is difficult to explain the impacts of such things as Water Budget, and it will be more difficult, if not impossible, to have them realistically reflected in the computation of Downstream Benefits of Treaty Storage.

- Power Discharge Requirements. The PNCA calls for Variable ECCs to be determined based on conservative forecasts of runoff and releases of project minimum discharges during the January-July period. Not long after Treaty Storage and Libby Project were completed, it was discovered that the Variable Energy Content Curves did not pass the test provided for them in Section 7 of the PNCA. That is, there appeared to be too high a probability of the system having disposable energy in excess of FELCC during the January-July period and then failing to fill. The PNCA provides, in such a situation, that the Variable ECCs must be adjusted "to those higher elevations necessary" to pass the test. The Refill Task Force, led by the Corps, looked into the problem and concluded that in years of low runoff the system could not produce FELCC with all the cyclical reservoirs shut down to project minimum discharges. In good water years, there is sufficient uncontrolled inflow to the system so that FELCC can be produced even with all major reservoirs releasing only project minimum discharges. The Task Force proposed to solve the problem by determining Power Discharge Requirements for each reservoir which would be used to construct Variable ECCs in any year when The Dalles January-July volume runoff forecast is below a certain level. When that forecast is above a higher defined level, project minimum discharges are used, and between the two levels, interpolated values are applied. The Corps has continued to

perform refill studies and to propose values of Power Discharge Requirements in every year since their first adoption.

Not mentioned here are the myriad and sometimes quite spirited debates which have graced the operations planning process, but which have only affected the division of benefits among the parties.

Operations

A number of very important interpretations and outright changes of PNCA operating provisions have been made since the Agreement went into effect. The most significant of these have been collected into a document, agreed annually, now called the Operating Procedures. As mentioned earlier, the Operating Procedures began as a means of recording the procedures hammered out for dealing with In Lieu Energy, and the document has been expanded through the years to include resolutions of additional operating issues as they were surfaced, debated and finally settled.

In the first few years, the Procedures addressed only In Lieu Energy. They established rules for application of lag-times, entrapments, scheduling restrictions and the like. Later, disputes flared up regarding Provisional Energy, primarily involving the reservoir owner's rights to declare that the water once drafted provisionally was now replaced. The resulting clarifications of Provisional Energy criteria were incorporated in the document; they have been expanded several times since they were first included.

Despite the operators' concentration for more than ten years on bringing order to the interactions required for In Lieu Energy, the actual scheduling of such Energy remained almost unbearably complex, time-consuming and acrimonious. The PNCA established a structure of bilateral rights and obligations between each reservoir and each downstream project, and even though the Procedures refined this structure in detail, they did not simplify it. Each project could in theory make a water request each day from each upstream reservoir owned by another party. As an example, Grant County PUD (GPUD) could make such requests for Wanapum from Hungry Horse, Flathead Lake, Pend Oreille Lake, Sullivan Lake, Priest Lake, Noxon Rapids, Coeur d'Alene Lake, Long Lake, Libby, Mica, Arrow Lakes, Duncan Lake, Grand Coulee and Lake Chelan. GPUD probably never tried to get releases from all those reservoirs in any single day for Wanapum but frequently tapped a number of them. If the reservoir owners decided to deliver In Lieu Energy instead of releasing the water, the schedules were laid out over the next several days depending on lag-times and possible entrapments, as the fictitious water was routed downstream. For each bottleneck, whether due to turbine capacity or natural outflow restriction, an allocation usually had to be made to determine which water was deemed to get through and which was trapped. Because U.S. requests for releases of Treaty Storage can only be made weekly, there was debate about the lag-time which should be applied to In Lieu Energy from Canadian reservoirs.

Adding enormously to this complexity was the fact that each Mid-Columbia non-Federal project had more than a single interested participant--and that most of the participants had interests in more than one Mid-Columbia project. GPUD's requests of releases for Wanapum Project,

therefore, were aggregates of the individual Wanapum purchasers' requests, and most of the purchasers had to determine daily their requests at each of several projects for each of several reservoirs. Scheduling and accounting among the purchasers in each project had assumed nightmarish proportions even before Mica and Libby were operable, and they were both slated to be in operation during 1973. It was certain that inclusion of those two large, cyclical reservoirs would substantially aggravate the scheduling burden. Incidentally, the complications and dislocations of the In Lieu Energy process were suffered by all affected parties, reservoir owners and downstream project owners alike; the same difficulties encountered by the downstream parties in getting In Lieu Energy were visited upon the reservoir owner when assigned water was released and In Lieu Energy was supposed to be returned. Furthermore, until the first turbine-generators were in service in the Third Powerhouse of Grand Coulee, scheduled for 1975, water was having to be spilled at that project more often to produce FELCC in the Mid- and Lower-Columbia. The PNCA provides that a downstream party may not request a release of water in excess of the reservoir project's maximum turbine capacity, unless reasonable forecasts indicate that the reservoir would otherwise be above its ECC at the end of the Drawdown Period; once the reservoir has reached this point, the PNCA places no limit at all on the daily rate at which releases may be requested. This omission was causing growing problems for BPA.

In 1973, BPA proposed a revolutionary package for the treatment of In Lieu Energy between the Federal System and the non-Federal Mid-Columbia Participants, and with some changes, the package was placed into operation in January 1974. This radical departure, which has benefited everyone immeasurably ever since its adoption, has these features:

- It treats each Mid-Columbia Participant (MCP) as if it owned a single project having a composite conversion factor and a composite maximum turbine capacity.

- It provides for scheduling directly between BPA and each MCP.

- It treats all Federal and Treaty storage above Grand Coulee Dam as a single composite reservoir, having a composite ECC and composite content, located at Grand Coulee.

- No entrapment in intervening reservoirs or time-lags between such reservoirs are applied, either on delivery or on return.

- No request for water may be made by an MCP which would require the total daily discharge at Grand Coulee to exceed its maximum turbine discharge capacity by more than 20 kcfs.

- No daily rate of return of In Lieu Energy in excess of the equivalent of 20 kcfs will be required of any MCP.

This package was modified in 1975 to allow BPA to reduce Grand Coulee's applicable maximum turbine discharge capability for certain outages of units in the Third Powerhouse, and it was further expanded to include Rock Island Project when new units were installed at that plant. Rock Island

had not been included in the original package because, with the ten-unit installation, it was spilling almost all the time and was not a significant factor in In Lieu Energy transactions.

Another first-magnitude package which improved operation under the PNCA was adopted in 1979. One of the fundamental concepts underlying the PNCA was that the Coordinated System would be operated (almost) as if owned by a single entity, with the diversities among the parties accommodated by transfers of Interchange Energy. This was to be accomplished, however, without establishing the single entity to direct the operation. The negotiators provided instead a large body of rules within which the combined individual operations were intended, in aggregate, to approximate the operation of the phantom single regional manager. In writing the relevant provisions, the negotiators relied on results of regulation studies which simulated system operation in monthly blocks, with all loads, flows, thermal performance and other data for each month assumed to be known at the beginning of the month. The hydro regulation models operated the system below ECCs when necessary to meet total Coordinated System FLCC with precise proportional drafts of each reservoir. Zero-sum transfers of Interchange Energy would flow from parties which had Actual Energy Capabilities in excess of their FELCCs to those having FELCCs in excess of the Actual Energy Capabilities.

The Agreement provides that each party will calculate its own Actual Energy Capability. It states (in a triumph of the passive voice) that, when drafts below ECCs are required to produce Coordinated System FELCC, each reservoir will be operated proportionally between the same respective pair of rule curves, as necessary to produce that total FELCC. It specifies that a party's Actual Energy Capability, on which are based its rights and obligations to Interchange Energy, will reflect the proportional-draft operation. However, it does not provide the individual party in actual operation any way of knowing the appropriate proportional draft levels, either of its own or of upstream reservoirs. And, since it does not provide rights to In Lieu Energy for water below ECC, it does not grant the downstream party the means to get the water above proportional draft levels, even if those levels were known. Another component of Actual Energy Capability is actual, or estimated actual, streamflows; there was no requirement that the parties employ common estimates of flow, even for participants in the same project. With no consistent basis for computing Actual Energy Capabilities, there was little credibility in the quantities which the parties claimed.

Until 1973, these problems were worrisome, but not actually damaging, because the region was in a state of firm energy surplus and enjoyed a string of good water years. Virtually no Interchange Energy was transacted under the rights-and-obligations structure of the PNCA, and there were few, if any, attempts to invoke those requirements. The drought of 1973, however, revealed the inadequacies of the PNCA to coordinate system operations under conditions in which generation was supposed to have been limited by FELCC. Efforts to remedy the problems began but stalled when good water returned. There were still no improved Operating Procedures in place when the more severe drought of 1977 occurred, but the parties resumed their efforts to solve the problems, this time in earnest.

The new provisions added to the Operating Procedures in 1979 contain several features:

1. They establish the Actual Energy Regulation (AER), to be performed by a designated Study Group. The AER is a continuous simulation initialized at the last time of full reservoirs, using actual natural streamflows for all past periods. For the current and one future month, the latest estimates (forecasts) of streamflows are used; all actual and estimated flows are submitted to the Study Group by the project owners. The regulation is updated at least monthly and may be run several times in a month, if conditions are tight and new flow estimates are substantially different from earlier submittals. The AER provides two sets of results:

    A. It determines the Proportional Draft Point (PDP) for each reservoir. If the Coordinated System can produce FELCC with draft to ECC levels, the PDP is the ECC. If it cannot, the PDP is the point (e.g., halfway between the first and second Critical Rule Curves) of proportional draft needed to generate FELCC.

    B. It specifies the hydroelectric component of each party's Actual Energy Capability, as a common, consistent basis for Interchange Energy rights and obligations.

2. They provide that the PDP so determined is substituted for the ECC wherever the latter is referenced in the operating provisions of the PNCA. This allows the reservoir owner to draft water down to the PDP and gives the downstream project rights to the same water, as In Lieu Energy, if it is not released.

3. They specify in detail the determination of Actual Energy Capabilities and estimates thereof for use during the current month.

Thus, after more than seventeen years of operation under the PNCA, its most fundamental concept was made to work. There have been many disputes about the implementation of these provisions, but in general storage operation has become orderly and dependable, and Interchange Energy transactions by the book have become commonplace. Although these provisions departed from the negotiators' intent of decentralizing the coordinated operation, they maintained the negotiators' principle that, whenever centralized determinations are necessary, sufficient procedures will be in place so that anyone having the same data will develop the same results. That is, no party's rights and obligations will be affected by anyone's judgment.

<u>Charges</u>

As noted earlier, the PNCA anticipated the need to adjust the "Other Charges" of Section 14 periodically, by giving each party the right to initiate negotiation of revised charges on notice given prior to July 1 of each fifth year. No party delivered such notice for the 1969 opportunity, but notices were given in 1974, 1979 and 1984. In the first instance the parties negotiated new charges among themselves, but in the latter two cases, the

issues had to be submitted to FERC and were settled only after FERC's Hearings process was underway. Much time, effort and money were expended in each review.

Strictly speaking, the modification of Other Charges is not a change of Coordinated System operation. However, since such Charges include prices for transactions, such as Interchange Energy Imbalances, and for services, such as Stored Energy, they do affect operations. The major issue in each of the reviews has been the Charge for Interchange Energy Imbalances. From the beginning, two schools of thought about Interchange Energy have been given expression. One is that Interchange Energy is a concomitant of the firming-up benefit of coordination; regardless of the identity of the marginal resource at the top of the dispatch stack, it is hydro diversity that causes Interchange; and if there is any charge at all for Interchange Energy it should be based on the cost of hydro energy. The other approach is that Interchange Energy is intended to be the firm resource of last resort; parties should be encouraged to purchase marketplace energy to the extent it is available at almost any price before demanding Interchange Energy from others; and the supplier should receive the higher of its incremental cost of supply or the market opportunity cost.

The problems of modifying the Other Charges have not been diminished by the PNCA's having provided a distinction between Interchange Energy supplied from hydroelectric sources and Interchange Energy supplied from thermal or miscellaneous (purchases) sources. It is unlikely that future reviews of Other Charges will be any easier than those of the past. In 1980 the Coordination Contract Committee adopted a set of Principles of Interchange Energy Pricing which helped to make the day-to-day scheduling process more dependable, and those rules are still in effect.

IV. Conclusion

The Region's power supply system and the conditions under which it is operated have changed greatly since the parties established the principles on which the Coordination Agreement was built. Those principles were an amalgam of responses to immediate, gritty problems of operation in the late 1950s and rather abstract, only partially tested ideas of how the future system of the Region should be operated. In the group of negotiators--indeed, within individual negotiators--there was always a broad mixture of motives, ranging from idealistically esthetic to basely money-grubbing. Those people did succeed, despite their differences, in constructing an Agreement which, as the keystone of electric power operations in the Northwest, has provided all parties greatly enhanced dependability and efficiency of power supply. Those people, and their successors, have successfully adapted the principles of the Agreement to changing conditions throughout the almost twenty-five years since it was executed. Some of the procedures adopted since the PNCA's execution may be seen as operating interpretations or clarifications of the Agreement's language which was expressed in generality, but others are unmistakably amendments of the PNCA provisions. None of them, however, has altered the concepts which comprise the foundation of the Agreement; indeed, those which changed the language of the PNCA are better implementations if the authors' principles than the provisions written by the authors themselves.

The process by which the PNCA has evolved, and continues to evolve, is not pretty, and the collection of Amendments, Operating Procedures, meeting minutes and unwritten understandings through which the changes have been effected does not constitute a clear, tidy means of codifying them. For one not involved in the almost continuous colloquy among the parties regarding implementation of the Agreement, it is difficult to determine with certainty what the current rules are and how they were developed. Given the nature of utility operators, who are accustomed to strong opinions, blunt debate and _ad hoc_, no-frills solutions, the process is unlikely to become more polished. But it works.

Topic 3
Historical Evolution of the Pacific Northwest Coordination Agreement

Commentary by Lawrence A. Dean

The following are my comments on Merrill Schultz' report on the above topic. I find Mr. Schultz' paper to be an accurate and thorough treatment of the topic. It generally agrees with my own recollection of the negotiation and implementation of the four agreements.

The single statement in his report to which I would take exception appears at the end of the subtopic II--The Third Agreement [p. 32]: "The new Agreement contained a clause allowing a reservoir owner to draft below ECC, so long as the forecast indicated high confidence of refill. Such additional releases were to be made at the sole discretion of the reservoir owner; downstream parties were not given the rights to demand the release or to receive In Lieu Energy from the extra water."

In fact section 9(o) of the new (ten-year) Agreement provided that at certain times the Energy Content Curves for certain reservoirs "shall be adjusted not more often than once a month to levels lower than the original Energy Content Curve when, in the opinion of the reservoir owner based on conservative forecasts made by the reservoir owner, there will be more water available than is necessary to refill the reservoir by the following July 31." Thus, while the contract gave a certain amount of discretion to the reservoir owner in making the forecasts, it required the lowering of the Energy Content Curves under the conditions described, and thus gave downstream plant owners access to the additional water. In fact, this provision caused considerable controversy in the spring of 1964 when, in the face of reasonably good water supply forecasts but with unsalable secondary energy, BPA refused to lower the Energy Content Curve at Hungry Horse. By the time the long-term Agreement was completed at the end of that summer, the reservoir owner's discretion had been reduced to developing methods for making inflow forecasts having a 95 percent probably of being equalled or exceeded and making those methods available to the other parties before the beginning of the contract year.

The balance of this comment paper consists of readdressing a part of Mr. Schultz' assignment from a slightly different perspective. In particular, I would like to give a somewhat different answer to the question: "How has operation under the (long-term) Agreement changed between its signing and today and what problems led to those changes?" Mr. Schultz provides a very thorough answer to that question. But what I would like to point out is that, while "operation under the Agreement" may have changed, the Agreement itself has not changed.

The long-term Agreement has a term extending 39 years from 1964 until 2003. The Agreement is admittedly a compromise among the 16 parties on numerous issues. Any general renegotiation of the agreement would require agreement of all the parties to every change or to a package of changes.

Because there are so many parties to the Agreement, and because they have such diverse interests, in my opinion there is litle practical possibility that a general renegotiation of the agreement will take place during its term.

The Agreement contains a section titled "Renegotiation." However careful reading of this section reveals that it does not provide effective procedures for renegotiating the Agreement. Nor, I believe, did any of the parties to the Agreement think that there would be any real opportunity to renegotiate the Agreement during its term.

Since 1964 there have been two addenda to the Agreement adding the U.S. Bureau of Reclamation and Snohomish County PUD as parties, and two amendments and one Federal Energy Regulatory Commission (FERC) settlement order revising charges under the Agreement. In section 14(j), Changes in Charges, where the negotiators anticipated that there would be a real need to effect change, the Agreement provides that, if "the parties fail to agree on revised charges, the parties ... shall submit the matter ... to the (Federal Power) Commission for determination of charges ...." The first attempt to revise charges resulted in agreement among the parties under threat that the matter would be referred to the FERC. The second attempt actually resulted in the parties taking their differences to FERC, and reaching agreement among themselves under the guidance of FERC. The third attempt resulted in FERC actually issuing a settlement order. So much for the ability of these many parties to reach agreement on any changes to the Agreement.

As Mr. Schultz points out, the Coordination Agreement Contract Committee has, from time to time, agreed on certain interpretations or what might even be considered revisions of the Agreement in order to keep it functioning. Many of these have been collected into a document known as the "Annual Operating Procedures for Operating Year 19_____ - _____ ." The operating procedures document for 1988-89 consists of 40 pages. It contains some very important modifications to the Agreement. In some cases it is signed by persons below the officer level in the companies or agencies. Getting the signature of representatives of all the parties on such a document each year can be extremely difficult and makes the document extremely fragile. In fact, the document is set up in such a way that, should one or more of the parties not sign it, the document would be effective among the parties who do sign it, but would not apply to those who choose not to sign it.

The problems with the existing Agreement are legion. Solutions to many of these problems have been worked out by the Coordination Contract Committee and are contained in the Annual Operating Procedures. But the need to obtain agreement to these procedures annually makes these solutions tentative. Other problems have not been solved.

Mr. Schultz' paper makes a list of the problems which are treated in the Annual Operating Procedures. They include:

- A whole panoply of procedures for implementing the In-Lieu Energy provisions of the Agreement. Many of these are beyond the plain meaning of the Agreement, for example the composite reservoir BPA

maintains at Grand Coulee, the scheduling of power directly between BPA and the utilities which purchase output of the non-federal mid-Columbia River projects, and the limitation of the maximum discharge capability which can be requested at Grand Coulee.

- Procedures for centrally computing the Actual Energy Capability of the Coordinated System and of each party, and therefore the rights to Interchange Energy of each party. The Agreement clearly contemplated that each party would compute its own Actual Energy Capability, but this turned out to be unworkable.

- The availability to downstream project owners of the water between the Energy Content Curves and the proportional draft points when the latter are below the former. The Agreement does not give this right.

- Methods for pricing Interchange Energy. While some of these can be regarded as clarifications of the Agreement, others, such as pricing Interchange Energy deliveries at the price of previously received Interchange Energy, cannot be so regarded.

Other significant problems either have not been amenable to solution or the solutions used so far have not been sufficiently acceptable to have found their way into the Annual Operating Procedures. Some of these are also mentioned in Mr. Schultz' paper. They include:

- Real-time determination of parties' Interchange Energy rights and obligations, or workable procedures for after-the-fact adjustments of Interchange Energy deliveries. This is a problem most people who are intimately familiar with the workings of the Agreement will admit exists, and one which causes considerable grief from time to time.

- Pricing of Interchange Energy. Based on the difficulties the parties have had in reaching agreement on past Changes in Charges Amendments, the parties obviously have had difficulty agreeing on the appropriate Interchange Energy pricing structure. The present structure leads to much game playing. Parties have been known to take Interchange Energy for the purpose of increasing their non-firm energy marketing if the price they have to pay for the Interchange Energy is less than prevailing non-firm energy prices. Worse yet, the Agreement permits this under certain circumstances.

- Shifting and shaping of Firm Energy Load Carrying Capability among months and between years in the Critical Period. In developing the procedures for operations planning under multiple-year critical periods. the drafters of the Agreement contemplated that the hydro system would be used to shift energy among months and years to fit the output from new large thermal plants to loads. However, to the best of my recollection, they did not anticipate that such shaping would be used to move firm energy surpluses or deficits between years within a critical period. During the past ten years, and especially since the Fish and Wildlife Program Water Budget flows have been required, the ability of the Coordinated System's hydro resources to accomplish all the shifting and shaping desired by the parties has encountered significant limitations. Methods

for determining the amount of shifting and shaping which the hydro resources can accommodate, and especially to define which parties to the Agreement have priority in its use should be developed and agreed upon.

- Coordinating the operation of thermal resources. Since 1964 the Pacific Northwest system has changed from a system which included numerous small, relatively high incremental cost thermal plants to one in which those plants have largely been retired and to which has been added a significant amount of large, low to medium incremental cost thermal plants. The Agreement adequately incorporates thermal plant capabilities into the annual operations planning process, but it does not provide any flexibility in the actual operation of those plants, nor does it provide any energy backup to unplanned outages of those plants. Although there was at least one unsuccessful attempt by the region's utilities to negotiate a separate thermal coordination agreement, there has been no attempt to incorporate the operating variability of thermal generation into the existing Agreement. This is one of the areas in which the existing Agreement could be improved.

A lot has changed since the Pacific Northwest Coordination Agreement was negotiated in 1964. And the way the power system is used to meet load will change more in the next decades. Some Pacific Northwest utility representatives have suggested the Pacific Northwest Coordination Agreement should merely be extended beyond 2003. I believe the parties to the Pacific Northwest Coordination Agreement deserve a chance to renegotiate that important agreement at least once every 30 years.

Topic 4

Relationship of the Coordination Agreement to Long-Term Planning

by Merrill S. Schultz
Commentary by Lawrence A. Dean

Topic 4
Relationship of the Coordination Agreement to Long-Term Planning

by Merrill S. Schultz

I. General

Prior Sections of this Report noted that some of the power pooling arrangements in other regions provide mechanisms for coordinated planning and construction of generating resources, and some even require joint participation in new resources. The PNCA has no such provisions, although there were proposals made during the negotiations to include language obligating the parties at least to coordinate their resource planning activities. The PNCA deals only with operations planning and actual operations.

However, there is a firm relationship between the PNCA and power supply planning in the Northwest. It is axiomatic that planning based on a bad representation of operations is bad planning. Obviously the results of the planning process, assuming it has any effect on decision-making, eventually affect operations. Several aspects of the PNCA must be understood by the capable planner; some of these are artificial creatures of the Agreement and others are reflections of the physics of the system.

II. Basic Operating Principles

There are perhaps three fundamental precepts on which the operation of the Coordinated System is based:

1. The System has a right to produce its hydro FELCC at all times, regardless of the reservoir storage situation. Whether hydro FELCC is based on Critical Water or any other criterion, it must be dependable in operation.

2. The System may not produce energy in excess of FELCC to the substantial jeopardy of annual refill. Another way in which this principle has been expressed is that the System's ability to produce future hydro FELCC may not be jeopardized by anything except producing current FELCC. This means that, although storage may be drafted to any level necessary to produce hydro FELCC, not one kilowatt-hour in excess of hydro FELCC may be generated until the current year's refill is virtually guaranteed.

3. Non-power requirements have priority over any use of the System for power.

A responsible planner may not produce any work based on the assumption of a hydro FELCC different from what is defined in the PNCA without first ensuring that the criterion defined in the PNCA will be altered to match, or without examining and describing the impact of the different FELCC in operations. He must understand that, if the FELCC under the

PNCA is insufficient to meet load at any time, there might be a real shortfall, even with plenty of water still stored in the reservoirs. That is, the PNCA provides each party the right to produce, or to receive Interchange Energy for, its hydro FELCC; there is no right provided any party to meet its firm load, as such.

Shifting and shaping of FELCC in the operations planning process prior to the year, together with flexibility to reallocate FELCC during the year, may help the planner to rely on postponing deficiencies of FELCC to periods when the expectation of having excess hydro energy is high. But these kinds of flexibility are not unlimited, and the planner must appreciate that the constraints on their use are growing ever tighter. Non-power considerations, chiefly fish and recreation, are frequently incompatible with economic improvements in the use of the hydro system and have absolute primacy in operations under the PNCA.

It should be noted that all the foregoing discussion was in terms of hydro FELCC. The PNCA provides no energy backup for the capabilities of thermal or miscellaneous resources. A party's Actual Energy Capability is computed using the capability of its hydro resources resulting from the Actual Energy Regulation, but it uses thermal and miscellaneous resource capabilities as submitted by the party prior to the year, regardless of the actual performance of such resources. The flexibility to reallocate FELCC in operation might allow a party to receive energy backup to accommodate, say, a change of maintenance schedule from that submitted in operations planning, from one month to another, but it provides no energy backup for the average annual energy capability. A delay of resource operation or a long forced outage of a thermal facility must be dealt with by the party owning the resource individually. The planner looking at resources other than hydro must be cognizant of both the limited ability of the party owning the facility to accommodate temporal deviations in its output through the PNCA and the total inability of that party to receive net annual energy backup for its planned capability.

III. Critical Water

There has been much discussion of the fact that the PNCA establishes FELCC on the basis of the most adverse historical streamflow regime. It should be understood that the authors of the PNCA did not ask themselves what criterion should be adopted as the basis for FELCC, discuss alternatives and agree upon Critical Water. Critical Water as the determinant of hydro energy capability had long been established in the Northwest by all parties and is, in fact, still commonly used around the world in situations where uninterrupted, streamflow-dependent services are considered essential. The negotiators simply accepted Critical Water as a "given" and set about writing provisions to implement its use. It had been adopted by BPA in the late 1930s as the basis for Computed Demand; it has always been used in the PNUCC West Group Forecasts, starting in about 1952; it was employed in all studies supporting both authorizations of Federal projects and licenses of non-Federal plants; and it was the criterion employed by the International Joint Commission in all of its analyses of what became Treaty projects. As to its credibility, it should be remembered that, until about 1972, the Critical Year was 1936-37. Many of the utility managers who were involved in the rapid

development of the Columbia River, beginning at about the same time, had very fresh personal experience of trying to meet load in 1936-37. They regarded such conditions as being quite credible, indeed, and had no qualms about adopting them as the basis for FELCC.

With the availability of electronic computers and the increased use of mathematical probability techniques converging in the late 1950s, the Critical Water criterion began to be questioned. BPA launched a major study, the Water Utilization Research Project, at about the same time as the framework of the long-term PNCA was being assembled. People involved in the scientific work expressed concerns about the wisdom of locking the Critical Water standard into place for 39 years, but the die was cast. The Principles and Procedures for establishing Operating Plans under the Treaty also incorporated the Critical Water criterion; those arrangements are not changed lightly or easily for any reason, and it must be considered unlikely that a departure from the Critical Water standard, which is enshrined in the Treaty itself, could be accomplished.

Thus, because the planner must comprehend the use of FELCC in operation and because adoption of a criterion for determining FELCC on any basis other than Critical Water is probably less likely than recurrence of Critical Water itself, the prudent planner should accept the PNCA's prescriptions for establishment and use of hydro FELCC in making resource-related analyses. Efforts to make better use of energy in excess of FELCC should focus on means of accomplishing that goal within the current structure, rather than by changing it (or by assuming it doesn't exist).

IV. Critical Period

There are no operating provisions of the PNCA which are directly dependent on the identity of the Critical Period which is the source of effective FELCC. Critical Period is defined in the Agreement primarily for the allocation of FLCC to the parties in the operations planning phase. However, the determination of Critical Period by the "load-growth" method can have unsettling consequences for the planner who assumes that some of the capability of a later-arriving resource can be borrowed for use in advance, or that some excess capability in the current year can be stored to meet later load growth.

It is generally assumed that the current Critical Period is within the four water years, 1928-32. The average hydro energy of the two-year critical period, 1943-45, is only about 50 MW greater than that of the four-year critical period. And the three-year period, 1929-32, produces only slightly more energy than the two-year critical period.

A sequence of resource installations which requires the hydro generation in the first two years to average more than 50 MW above the four-year average will result in establishment of a two-year Critical Period; this will prevent borrowing of additional energy from the third and fourth future years. In the other direction, only a small amount of energy can be moved out of the first year before system storage runs up against full at the end of the first year of the four-year critical period--this deprives the future years of

energy which might have been counted on and results in a very strange Critical Period for the first year.

Therefore, although the planner may depend on some amount of year-to-year shaping, only limited mismatches of annual load growth and resource installation can be tolerated unless the planner is willing to accept frequent firm surpluses of FELCC.

Furthermore, as noted in the preceding section, first-year-end reservoir draft limitations have severely restricted the parties' ability to produce hydro FELCC in the first year in excess of the "uniform-hydro" quantity.

V. Annual Average Secondary Energy

The fact that the System is capable of producing energy in excess of FELCC in most years is not a recent discovery. Before Treaty Storage and before the Intertie, in fact, the System spilled energy for lack of market in every year and would have spilled with a recurrence of the Critical Year, even with all reservoirs empty on April 15. Utility planners and operators have sought ways of making that energy first usable, and then usable at a higher value, ever since the earliest days of the hydro system. There are, in general, two ways of accomplishing this goal.

First, one might convert secondary energy to prime energy[1] by acquiring more reservoir storage. Because this process increases FELCC and delays acquisition of additional generation or conservation resources, it has been given a very high value, assuming there is load growth. Since reservoir storage trims off the peaks of the hydrograph, it makes usable not only flows which formerly spilled for lack of market, but also flows which once spilled past turbine capacity. Storage provides ancillary benefits too, such as flood control, but it raises hob with the life-cycles of anadromous fish. A similar "firming-up" function may be served to a large extent by exchange agreements between hydro-based and thermal-based systems, but without modifying flows.

Second, one might locate a valuable market for the secondary energy. This could take the form of an interruptible load or it could be a fuel displacement market, in which the secondary hydro energy would displace the use of expensive fuels for generation of electricity. Usually, this alternative is thought to yield a lower value than does conversion of secondary to prime, because it only saves incremental production costs, whereas conversion saves capital costs, as well.

Northwest utilities have exercised both options. They have acquired storage to the extent that hydro FELCC of the System if now about three quarters of the annual average streamflow capability: it is highly improbable that any significant portion of the remaining quarter can be converted to prime through construction of additional reservoirs. One quarter of the load

---

1./ These terms are more appropriate to the hydro resource than are, respectively, "non-firm energy" and "firm energy" which should refer to the conditions of a transaction.

of BPA's Direct Service Industrial customers has long been treated as interruptible. In addition to Northwest utilities' acquisition of displaceable resources, construction and expansion of the Pacific Intertie has provided the Region a huge fuel-displacement market. If the Third A-C Intertie is built, total Intertie capacity of 7,900 MW will remove transmission for all practical purposes as a limitation on the usability of average annual secondary energy.

Unfortunately, the secondary energy, averaging about 4,000 MW, does not occur in reasonably uniform annual amounts. In 20-25 percent of the years, there is none at all because the System does not fill, and the PNCA prohibits production of secondary energy when System storage is below refill levels. This means that, in years when there is secondary energy, the annual average secondary energy is substantially greater than 4,000 MW. And, unfortunately, in years when there is secondary energy, it does not occur in reasonably uniform monthly amounts. Compared with the first year of the Critical Period, 1928-29, most of the additional water of a good year does not appear in the streams until the beginning of the spring freshet. The PNCA permits use of the additional water as soon as reliable snowpack-based runoff forecasts are available, however, early in January. That is certainly better than having to wait for the water to appear in the streams, but it still concentrates most of the annual average secondary energy into the second half of the operating year.

The creative planner might have an idea for "playing the water game;" the System could simply borrow FELCC from later in the Critical Period and increase FELCC in the first year. If good water occurs, the System will have more usable secondary energy, reservoirs will fill and the System will start the next year with a clean slate. If the System does not fill in the first year, there is still a good chance it will recover in the second. Only if the periods from which FELCC was borrowed are encountered without intervening refill will the System have to find some other way of meeting load. Alas, the PNCA does not permit this kind of scheme, either by shifting FELCC from year to year or by shaping FELCC within the first year. Section 6(g) prohibits any party from having FELCC in excess of its firm commitments in any month if its FELCC is less than its firm commitments in another month.

By the way, this prohibition is one of several in the PNCA which appear to be inconsistent with the boldly stated principle, Section 9(a), that a party may use its FLCC "for any and all purposes." It is consistent, though, with what the authors really meant, which was that a party may use its FLCC for any and all purposes--except to get itself in so much trouble that it would have to be rescued by the other parties.

For many years planners have examined the economics of installing thermal resources having low capital costs and high production costs; the extreme of this characteristic is represented by simple-cycle combustion turbines. These resources are attractive because of the way they might interact with the existing System of base-load thermal resources and hydroelectric facilities, the latter producing abundant secondary energy in most years. Indeed, in the screening curves which utilities have commonly used as guides in selecting types of new resources, combustion turbines have appeared as the most economic alternative if they can be depended on to operate below certain capacity factors. Of course, the cross-over capacity factors have varied

substantially from case to case depending on heat-rate, fuel cost and the actual or opportunity cost of displacement energy. Although Northwest utilities have installed such resources, and in substantial amounts, virtually none was acquired on the basis of long-term economics.

In the examination of the cost-effectiveness of such resources, the planner must take special pains to make sure that the workings of the PNCA, both in operations planning and in operations, are appropriately taken into account. He must be particularly aware of the potential self-deception he might commit through the naive use of averages.

An additional factor which should at least be considered in any effort to make better use of what is currently secondary energy is that there are a number of entities which did their planning, and made their decisions, based on the current situation. Several Northwest utilities have installed combustion turbines as firm energy resources and continue to depend on the accustomed availability of displacement energy. Northwest and Southwest utilities have invested considerable money in transmission lines, and are contemplating new investments, for transferring secondary energy. BPA's Direct Service Industries made substantial commitments in the Regional Power Act in order to get new contracts, based partly on expectations of a high level of service to their First Quartile loads. Such entities might not consider conversion of secondary to prime to have the highest of all values, and they might be uncomfortable sharing the current supply of secondary energy with a substantially enlarged market.

The PNCA provides no pooling of Coordinated System secondary energy; it belongs to the party which produces it. Therefore, although secondary energy has practically no production cost to the Coordinated System, it might have substantial cost to the party with a displaceable resource if another party generates it. Furthermore, if one party has excess water in storage, the party is under no obligation to produce secondary energy with it for another's displacement. The wise planner must realize that a resource which is most cost-effective for the Region might not be cost-effective for the party expected to install it. This might help explain why several utilities which already own combustion turbine generation decline to declare their existing capabilities as Firm Resources, despite studies showing that the Region can install new ones cost-effectively.

VI. Interchange Energy

Under the PNCA, Interchange Energy can be a very expensive diversity exchange. The Agreement, as elaborated in the Principles of Interchange Energy Pricing, provides that Interchange Energy is deemed to flow from the first resource in the Actual Energy Capability stack above FELCC and is priced accordingly. Interchange Energy once delivered cannot be forced back unless the original delivering party, or some other party, needs it. Thus, the PNCA assures firm backup for any party's FLCC and permits the party to shape its FLCC as needed, but the party might have to pay thermal-based prices for the backup of its shaping.

As an example, assume that one party--even BPA, the largest and possessor of the greatest amount of storage--installs combustion turbines (CTs)

and shapes some of its Critical Period FELCC into the early months of the Critical Period to avoid running the CTs. For the increment of FELCC, reservoir draft is increased in the early months, but only in an amount necessary to produce the increment on the total System. The party's hydro energy capability is only increased by its share of the total head downstream from the particular reservoir, and the remainder is indicated to flow to it as Interchange Energy from the other parties downstream from the reservoir. This might make another party's CTs, not hydro, available as a source of Interchange Energy to the first party--for displacement of its CTs!

Some of this exposure to high-cost Interchange Energy is alleviated by Holding Interchange Energy (but only in the first two periods) and can be lessened, but not eliminated, by the adjustments of the Modified Regulation permitted by the Agreement. But the planner should understand why even the largest party in the PNCA might be a nervous owner of CTs, even if they are demonstrated to be cost-effective for the Region.

VII. Reserve

Anticipating that the System would become capacity-critical during the term of the PNCA, and for the other reasons described in prior Sections of the report, the authors of the Agreement provided a rather comprehensive treatment of capacity, including determination of Forced Outage Reserve. Although it has been postponed substantially, the day will come when consideration of peak loads and resources is important to the planner.

The method laid out in the PNCA for computation of Forced Outage Reserve represents a bit of a turnabout, inasmuch as it is an adaptation to operations planning of a technique invented for resource planning. As its name implies, Forced Outage Reserve is provided to guard against inability to meet peak load due to forced outages of generating units. The planner should note that Forced Outage Reserve, while probably appropriate to next year's operations planning, is only one element of the reserve that should be planned at the time when the decision to acquire resources is made. In addition to forced outages, the planner must protect against "dry holes," construction delays and errors in the secular trend of load growth, among other uncertainties which might arise during the lead-time of a new resource.

This is the reason for the formulation of reserve requirement used in the PNUCC Northwest Regional Forecast. In that document, reserve is defined to be 12 percent of installed capacity in the next year; this quantity is intended to be roughly equivalent to Forced Outage Reserve. However, for each succeeding year, reserve is increased by one percentage point until it reaches 20 percent, and it remains constant thereafter. Thus, planning uncertainties other than forced outages are tacitly expected to increase with each year in the future until a maximum practical reserve requirement is reached. And PNUCC's expectation is that the System should try to install 20 percent reserve in a future year so that it can be assured of having 12 percent reserve when it gets there.

VIII. Conclusion

The Coordination Agreement represents an attempt by the utilities of the Northwest to capture as much of the benefit of centrally managed operation as possible without the central manager. It allows the parties the ability to take advantage of diversity, and it provides assurances of scheduled water releases and backup of each party's FLCC. The rules which it includes for operations planning and operation of the Coordinated System must be understood in resource planning, whether for an individual utility or for the Region, lest the planners' evaluations of cost-effectiveness be catastrophically misleading.

The PNCA contains no provision for the coordination of planning or resource acquisitions; this omission was made consciously and deliberately. It contains no formula for allocation of Regional economic benefits, and it makes no guarantee that a resource option which is cost-effective for the region will be cost-effective for any party. The parties, or most of them, anyway, wanted to continue to do their planning and resource acquisition independently. The PNCA, in short, does not provide the economically monolithic regional system which is assumed in several of our planning models to exist. Nothing does.

The PNCA does not prevent such coordination, however, and it might be an interesting project for someone to devise a proposal for a new Regional dollar-coordination, in addition to the existing MW-coordination. Until such a proposal is made and adopted, however, the Regional planner should be acutely sensitive to the potential pitfalls of making resource-related recommendations on the basis of Regional computer models which assume economic integration.

Topic 4
Relationship of the Coordination Agreement to Long-Term Planning

Commentary by Lawrence A. Dean

The following are my comments on Merrill Schultz' report on the relationship of the Pacific Northwest Coordination Agreement and power supply planning. Mr. Schultz' report is a comprehensive and veracious discussion of a number of important topics which the Agreement addresses and which have important impacts on power supply planning. As such, I have no critical comments on it.

In responding to the question about the relationship between the Pacific Northwest Coordination Agreement and regional resource planning, I would like to emphasize one point which both Mr. Schultz and I make elsewhere in these reports: the Agreement does not cover coordinated resource planning by the parties. The subjects of resource planning and firm sales among the parties to the Agreement were intentionally not included in the Agreement. This does not keep the Agreement from having important implications for resource planning. Of course it does, and these are discussed in Mr. Schultz' report.

I would like to add my own opinions to his on the subject of whether it may be possible to change the use of the critical period as defined in the Agreement as the basis for hydro firm energy load carrying capability. Near the end of his discussion of Critical Water (subtopic III) which appears at the the top of [page 51], Mr. Schultz states: "it must be considered unlikely that a departure from the Critical Water standard ... could be accomplished;" and "adoption of a criterion for determining FELCC on any basis other than Critical Water is probably less likely than recurrence of Critical Water itself." I agree with Mr. Schultz that there are sound reasons for using Critical Water or another similarly conservative basis for establishing the firm load carrying capability of the hydro system. And I agree that changing from Critical Water as defined in the Agreement would be difficult. But his expression of near impossibility is stronger than I believe is the case.

In my opinion, it would be possible, albeit difficult, to base hydro system firm energy load carrying capability on some other conservative, but perhaps somewhat less conservative, criterion in a new coordination agreement. The basis for such new criterion would have to be very sound. After all, it establishes the level of capability which each party is entitled to have supported by the other parties to the agreement, and thereby limits the other parties' use of their resources for other purposes. Degradation of the criterion would also put the region at greater risk of region-wide firm power shortages. The relationship between the coordination agreement and the Columbia River Treaty will also require much thought before any change of this type is made in the Coordination Agreement. The basis for firm energy load carrying capability does not have to be the same in the two documents, but there obviously is a strong relationship between the two which must somehow be made consistent. B.C. Hydro personnel have indicated that they do not

consider it impossible for the two documents to use different criteria. But the effect of any change in the coordination agreement on the operation of Treaty reservoirs, and most importantly on the Canadian entitlement would have to be carefully monitored by both U.S. and Canadian interests. Lastly, the BPA power sales contracts are firmly rooted in selling firm power to generating utility customers in excess of that which they can produce from their own facilities, and it uses the Coordination Agreement procedures to determine the firm capability of the customer's resources. Any change in the Coordination Agreement would have to be reflected in a similar change in those contracts.

I would like to use these comments as an opportunity to reiterate a point I made in my reports on Topic 1, and to add a little information to that subject. Prior to 1961 the Northwest Power Pool was preparing annual operating plans and the Pacific Northwest Utilities Conference Committee was preparing resource planning documents which assumed full coordinated operation among the region's utilities. Individual utilities, including BPA, used similar studies to determine their needs for additional resources. So the Coordination Agreement did not decrease the region's needs for new resources. It merely made a reality out of what had been an assumption: that the regions's resources were operated in a fully coordinated fashion. When the long-term agreement was signed in 1964 BPA was anxious to boast about its accomplishments. I was assigned the task of determining the amount of new firm resources which could be avoided because of the signing of the Agreement. Not having the clarity of view which I now have, I struggled mightily with this task. What should be assumed for the "without coordination" case? Were Seattle and Tacoma already coordinated? Were the four investor-owned utilities which operated under the Inter-Company Pool already coordinated? How much storage release from federal reservoirs could downstream non-federal hydro projects depend on without the Agreement? The end product was a study which indicated, I think (I cannot now find any remnants of it), that the region's utilities would avoid the need for about 1,000 average megawatts of new firm energy resources. This number, if it is correct, amounted to about 12 percent of the coordinated system's approximately 8,300 average megawatts of firm energy load carrying capability at the time.

In closing, I would like to repeat a point which Mr. Schultz makes in his report, and which has been made before in other forums. Good resource planning must take into account how the system will be operated, and therefore presumably how the system is operated. Similarly, good resource operations must reflect the assumed operational schemes which were the basis for the decisions to add particular new resources. Both resource planning and resource operations benefit from knowledgeable incorporation of each discipline into the other.

Addendum

by Lawrence A. Dean